Wind Power Capacity Credit Evaluation Using Analytical Methods

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By

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Abstract

Wind power is the most mature green energy source in electric power systems and is now a booming worldwide industry. The use of wind power is growing rapidly throughout the world to reduce environmental degradation. Due to global environmental concerns and public awareness, many power utilities around the world are considering wind energy as a substitute for conventional generation. Many governments already have energy plans and policies in place to ensure significant increase in power generation using wind energy within designated time periods. The wind is variable, site specific and is an intermittent source of energy. It is therefore a complex task to analyze generating system capacity adequacy considering wind energy. The growing application of wind power dictates the need to develop methods to evaluate the system reliability and the capacity value of wind power. Wind is generally considered to be a source of energy, rather than a power source. It is equally important however, to consider the capacity credit of wind power as its penetration increases in electric power systems. It is very important for both electric power utilities and wind power developers to accurately assess wind capacity credit and therefore it is necessary to study and develop different methodologies for performing this task. The research presented in this thesis examines a range of methods used for the evaluation of wind capacity credit using data from four wind sites in Saskatchewan. The techniques, methods and results presented in this thesis should prove to be valuable for system planners assessing generating capacity adequacy evaluation incorporating wind energy.

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List of Abbreviations

ARMA	Auto Regressive and Moving Average
CanWEA	Canada Wind Energy Association
CC	Capacity Credit
CLU	Capacity of the Largest Unit
COPT	Capacity Outage Probability Table
CR	Capacity Reserve
CRM	Capacity Reserve Margin
DAFOR	Derating adjusted forced outage rate
DPLVC	Daily Peak Load Variation Curve
EFOR	Equivalent Forced Outage Rate
EIR	Energy Index of Reliability
ELCC	Effective Load Carrying Capability
FOR	Forced Outage Rate
HL	Hierarchical Level
IC	Installed Capacity
LDC	Load Duration Curve
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
MTTF	Mean time to failure
MTTR	Mean time to repair
MW	Megawatt
PJM	Pennsylvania-New Jersey-Maryland
PL	Peak Load
PSIWE	Power System Including Wind Energy
RBTS	Roy Billinton Test System
RTO	Regional Transmission Organization
RTS	Reliability Test System
SM	System Minutes
SPP	Southwest Power Pool
SW	Simulated Windspeed
UPM	Units Per Million
WECS	Wind Energy Conversion System
WTG	Wind Turbine Generator

Chapter 1

Introduction

1.1 Power system reliability

Power system reliability evaluation is important in providing adequate and acceptable continuity of supply. The term reliability associated with a power system is a measure of the ability of the system to perform its basic function, which is to provide electric energy to the customers as economically and reliably as possible [1]. More reliable systems require more financial investment. It is impossible and therefore impractical to attempt to design a power system with a hundred percent reliability. Therefore power system planners always attempt to provide a reasonable level of reliability at an affordable cost. The consumer's probability of being disconnected can be reduced by increasing the investment during the planning phase, operating phase or both. The term 'reliability' provides an extremely broad perspective and includes all aspects of the ability of a power system to perform its basic function. The concept of reliability can be subdivided into the two distinct aspects of system adequacy and system security as shown in Figure 1.1.

System adequacy deals with the existence of sufficient facilities within the system to satisfy the customer demand. These facilities include those necessary to generate sufficient energy and the associated transmission and distribution networks required to transfer the energy to the customer load points. Adequacy therefore deals with static system conditions rather than system disturbances. This thesis is restricted to

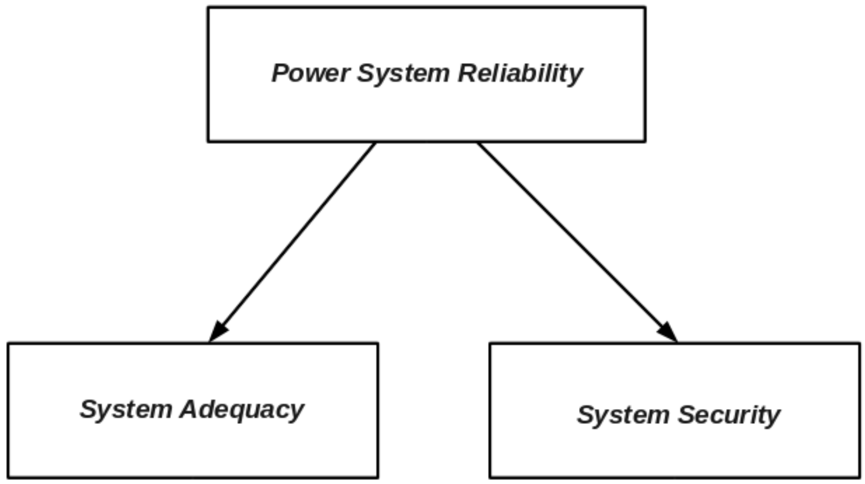

Figure 1.1: Subdivision of system reliability.

adequacy assessment of generating capacity. System security deals with the ability of the system to respond to disturbances arising within the system. Therefore system security deals with the ability of the system to respond to the disturbances that arise. A modern power system is very large, complex and interconnected. It is difficult and impractical to conduct an adequacy evaluation of an entire power system. A power system is therefore divided into the three basic functional zones of generation, transmission and distribution systems [1, 2, 3] as shown in Figure 1.2.

The above three functional zones can be combined to form hierarchical levels. The system adequacy can be studied at each hierarchical level (HL). The concept of HL has been developed [1] in order to identify and group these functional zones. The first level (HL-I) illustrated in Figure 1.2 is concerned with the generation facilities and their ability to satisfy the system demand. Reliability assessment at HL-I is normally termed as generating capacity adequacy evaluation. The reliability of the transmission and distribution systems and their ability to move the generated energy to the consumer load points are not included in this level. HL-I adequacy evaluation

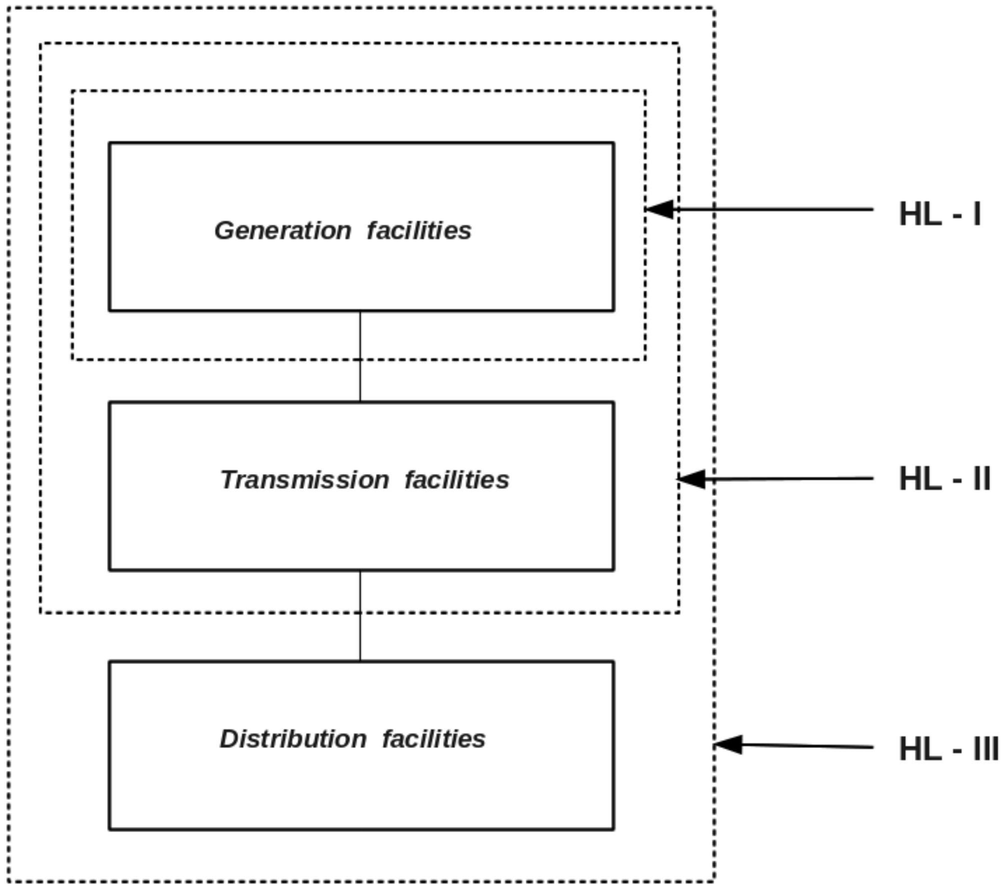

Figure 1.2: Hierarchical levels.

is an important area of power system reliability assessment.

It is also the oldest and the most widely studied aspect of power system reliability evaluation. The basic model at HL-I is shown in Figure 1.3. The model shown in this figure is used to decide when and how much additional capacity is required to meet the system load demand. Adequacy evaluation at HL-II includes both generation and transmission facilities. HL-II deals with the ability of the combined generation and transmission system to generate and convey energy to the major load points. This analysis is usually termed as composite system reliability evaluation or bulk power system reliability evaluation. Adequacy evaluation at HL-III includes

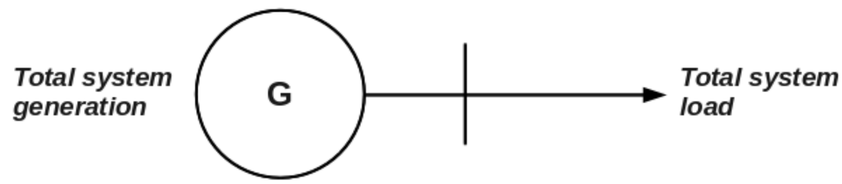

Figure 1.3: Basic model for HL-I study.

all of the three functional zones. HL-III deals with the complete system including the distribution and its ability to satisfy the capacity and energy demands of the customers. Complete HL-III studies are not easily conducted in a practical system due to the computational complexity and scale of the assessment. These analyses are generally performed only in the distribution functional zone. This thesis is focused on HL-I evaluation.

1.2 Power systems including wind energy

Wind energy is one of the fastest growing electrical energy sources and is a booming world wide industry. Wind energy is produced by the uneven heating of different parts of the earth's surface. The differences in temperature creates differences in atmospheric pressure, which results in flow of air or wind. A wind energy conversion system (WECS) converts the wind's kinetic energy into electrical energy. The basic idea of a WECS is quite simple. The wind strikes a set of blades which are mounted on a shaft i.e. free to rotate. The wind hitting the blades generates a force that turns the shaft. The rotating shaft turns an electric generator that converts the rotational kinetic energy into electrical energy. Wind power has been used to sail ships, run small sawmills, grind grains and pump water from wells. Wind energy has zero fuel cost, zero emissions and zero water use. Due to global environmental concerns and public awareness many power utilities around the world are considering wind energy as a substitute for conventional generation. Now wind power is increasingly used for generating electricity. The use of wind power is increasing rapidly at an annual rate of 30% with a worldwide installed capacity of 121,000 Megawatt (MW) in 2008 [4], and is widely used in the United States and in European countries [5]. The U.S. and Texas Wind energy markets experienced a rapid growth in capacity in the last three years [6]. Today Texas has the world's largest onshore wind farm in the Sweetwater area. In 2007, Texas installed wind capacity of 4,296 MW, which is enough to power about one million homes, based on the average electric consumption in 2006. At the end of 2007, the installed wind capacity in the U.S. increased to 16,596 MW, which is enough to power about 5 million homes, depending on their average consumption in 2006 [7]. Figure 1.4 shows a wind farm in West Texas.

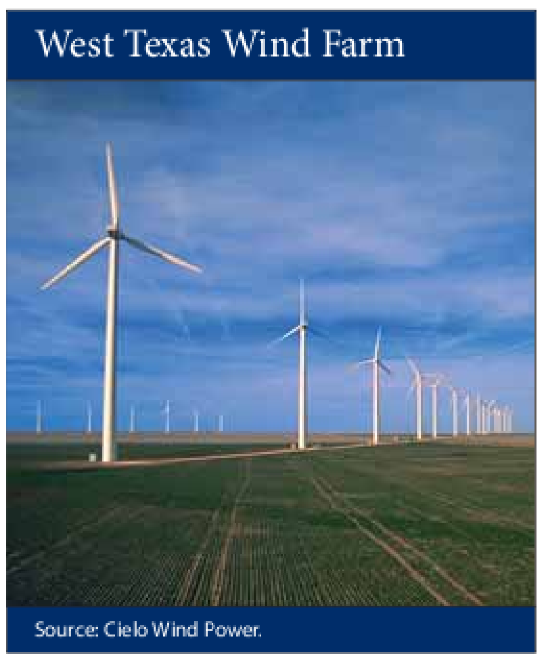

Figure 1.4: A wind farm in West Texas [6].

Canada's installed capacity on Nov 2009 was 3,150 MW. Canada passed the 3,000 MW mark in 2009 with new installed capacity from wind energy projects totaling 790 MW. Canada's previous highest year in terms of installed capacity was 2008 [8]. Figure 1.5 shows the wind power capacity in Canada published by the Canada Wind Energy Association (CanWEA).

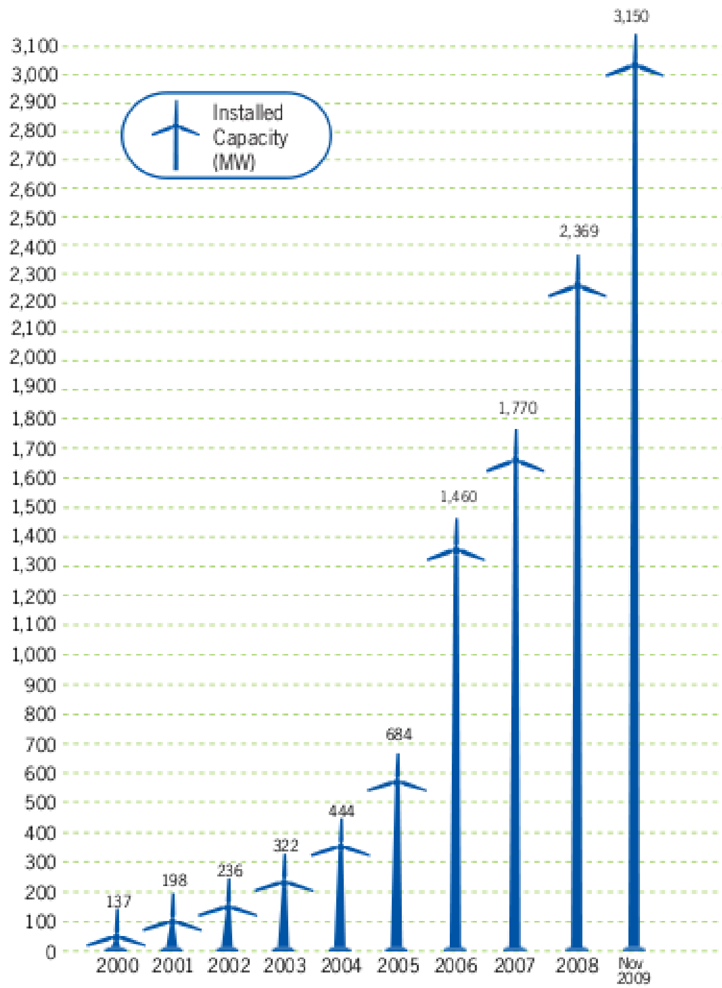

Figure 1.5: Current installed wind capacity in Canada [8].

CanWEA indicates that the goal of providing 20 percent of Canada's electricity needs with wind energy will be achieved by the year 2025 [9]. Figures 1.6 and 1.7 show the global installed capacity and annual installed capacity data by region.

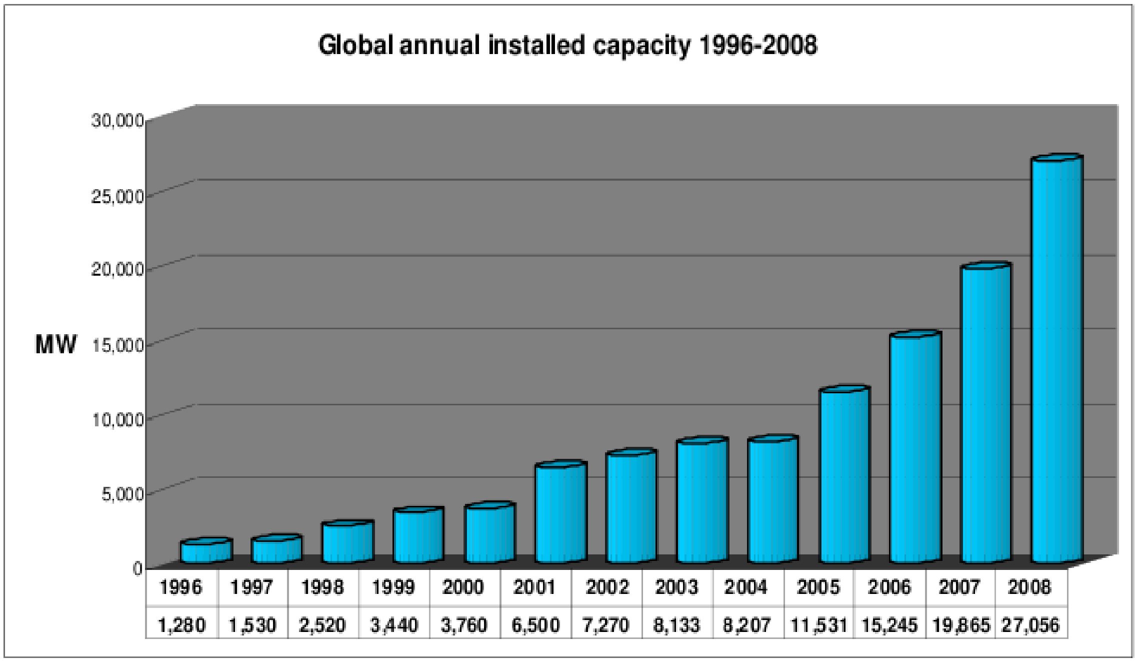

Figure 1.6: Global installed wind capacity [10].

Wind is highly variable and site specific and is therefore an intermittent source of energy. The power output of a wind farm site fluctuates depending upon the variability of wind speed with time. It is therefore relatively complex to analyze generating system capacity adequacy considering wind energy. Different mathematical models and techniques have been developed to conduct reliability evaluation of power systems with wind energy. An accurate model is required in order to forecast wind speed variations at a particular wind farm site. Historical hourly data at a wind farm location of interest can be collected over a reasonable period of time and simulated using a time series auto regressive moving average (ARMA) model [11]. Based on historical wind speed data, future hourly data can be predicted using the time series model. This model has been used to conduct reliability studies containing wind energy [12, 13, 14, 15, 16]. The process required to obtain the proper ARMA model for a site of interest is quite complex and historical wind data are not

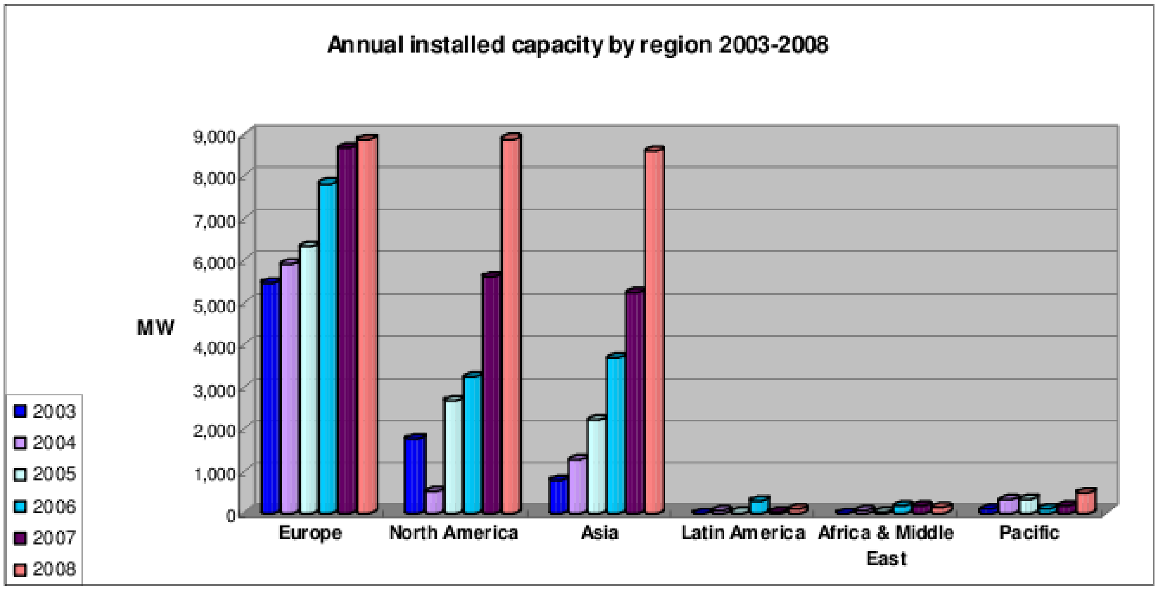

Figure 1.7: Annual installed wind capacity by region [10].

always available for all potential wind farm sites. Increased attention is being given to the area of wind power and reliability as wind power penetration levels continue to increase in electric power systems. Relatively high wind penetration levels can have a great impact on the performance of a power system. Increasing wind penetration levels require large capital investments in wind facilities and therefore, it is very important to evaluate the capacity credit associated with WECS. Wind is generally considered as a source of energy but not as a source of capacity. It is therefore important to examine the different power system reliability methodologies used to assess the capacity credit of wind power.

1.3 Research objective and overview of the thesis

It is difficult to accurately predict the behavior of the wind and therefore, evaluation of the capacity credit of wind energy is an interesting subject of study. Capacity credit is a measure of the load carrying contribution that wind power can make to an electric power system. The basic objective of this research is to examine the range of methods used for the evaluation of WECS capacity credit using data from four wind sites in Saskatchewan. The basic objective is achived using the following steps:

1. The different available methods for capacity credit evaluation were considered and several methods were selected for further study.
2. Wind power capacity credit evaluation was conducted using the selected methods.
3. The capacity credits attributable to several wind sites in Saskatchewan were evaluated.
4. The influence on the wind capacity credit due to different wind data, wind penetration levels and peak load were studied.

Analytical techniques [1] have been utilized in the studies described in this thesis for generating capacity adequacy evaluation. Generating capacity adequacy evaluation consists of developing a generation model and a load model and combining these models to create a risk model. The procedure is described in detail in Chapter 4.

Chapter 1 introduces the basic concepts related to power system reliability evaluation. This chapter also introduces power systems utilizing wind energy and the growth of wind energy applications throughout the world. It also outlines the importance and the main objectives of this research work.

Chapter 2 describes the time series model that has been used to simulate the hourly wind speeds and WTG modeling. It also presents the test systems and the load model used. It introduces the apportioning method that has been used to develop a multi-state WECS model.

Chapter 3 introduces two different methods knows as the Southwest Power Pool method (SPP) and the PJM method for capacity credit evaluation. It also presents the capacity credit obtained using the two methods using parameter variation analysis i.e., for different wind sites, different WTG and changing percentile values for the SPP. It presents a comparison and some general conclusions.

Chapter 4 presents the basic reliability techniques applied in generating system adequacy evaluation. It also describes the relevant system reliability indices. Reliability indices such as the loss of load expectation (LOLE) and the loss of energy expectation (LOEE) are described in this chapter. The Effective Load Carrying Capability (ELCC) method is introduced and used for capacity credit evaluation.

Chapter 5 summarizes the thesis and presents some general conclusions.

Chapter 2

Wind Power Modeling

2.1 Introduction

Wind is an important source of energy and is considered to be an encouraging and promising alternative source for power generation because of its tremendous environmental and social benefits together with public and government support. It behaves far differently than many conventional energy sources. This is because of the variability in wind speed and the dependability of the power output of each wind turbine generator (WTG) in a wind farm. Considerable effort has been focussed on the reliability evaluation of power systems containing wind energy. This chapter presents the models required to perform generating capacity adequacy evaluation of a power a system containing wind energy. The generation model and load model are combined to create a suitable risk model. The development of a generation model for a power system containing wind energy requires the combination of two major factors designated as wind speed modeling and wind power generation modeling. An apportioning method is introduced and used to develop a multistate model for a wind energy conversion system (WECS) consisting of multiple WTG [17, 18].

2.2 Wind speed model

Wind speed varies with time, and site and at a specified hour is related to the wind speeds of previous hours. Considerable work has been conducted in the development and utilization of wind speed models. An auto- regressive moving average time series model (ARMA) was developed to incorporate the chronological nature of the actual wind speed [11]. Based on historical wind speed data for a specified site, future hourly data can be predicted using the time series model. This model has been utilized to perform reliability studies containing wind energy[12, 13, 14, 15, 16]. The ARMA time series models are used in the research described in this thesis to generate synthetic wind speed data based on the historical wind data at specific site locations. The ARMA (n,m) time series model (Auto-Regressive and Moving Average Model) can be expressed mathematically as follows

$$y_t = \phi_1 y_{t-1} + \phi_2 y_{t-2} + ... + \phi_n y_{t-n} + \alpha_t - \alpha_{t-1}\theta_1 - \alpha_{t-2}\theta_2 - ... - \alpha_{t-m}\theta_m \quad (2.1)$$

where y_t is the time series value at time t, $\phi_i(i = 1, 2, ..., n)$ and $\theta_j(j = 1, 2, ..., m)$ are the auto-regressive and the moving average parameters of the model, respectively; α_t is a normal white noise process with zero mean and a variance of σ_a^2, i.e., $\alpha_t \in NID(0, \sigma_a^2)$, where NID denotes Normally Independent Distributed. The simulated wind speed SW_t can be obtained from the historical mean wind speed μ_t, standard deviation σ_t and the time series values y_t as follows

$$SW_t = \mu_t + \sigma_t \times y_t \quad (2.2)$$

The hourly mean wind speed and the standard deviation data should be collected for a specific site. The time series ARMA model described in Equations (2.1) and (2.2) was used to generate simulated wind speed data. The main steps can be briefly described as follows.

1. Generate white noise α_t
2. Generate y_t from the present white noise α_t and previous values of y_{t-n} using the time series model in (2.1).
3. Determine the simulated wind speeds at time points using (2.2).
4. Determine the hourly wind speed data using steps 1 to 3 for a calender year.
5. Repeat step 1 to step 4 for a long period.

Different site locations usually experience different wind regimes, and therefore the ARMA time series model for different locations are different. The wind speed models and data from four sites (Swift Current, Regina, Saskatoon and North Battleford) located in the Province of Saskatchewan, Canada have been used in the studies conducted in this thesis.

Figure 2.1: Location of the four wind sites.

The geographic locations of these four sites are shown in Figure 2.1. The hourly mean wind speed and the standard deviation from a 20-year data base (from Jan 1, 1984 to Dec 31, 2003) for four different Saskatchewan sites were obtained from Environmental Canada. The mean and standard deviation of the wind speeds at the four different sites are given in Table 2.1.

Table 2.1: Wind speed data at the four different sites of Saskatchewan, Canada.

Site	Mean wind speed μ (km/hr)	Standard deviation σ (km/hr)
Swift Current	19.46	9.70
Regina	19.52	10.99
Saskatoon	16.78	9.23
North Battleford	14.63	9.75

The ARMA models for the four sites developed by the Power System Research Group at the University of Saskatchewan [11] are given in (2.3), (2.4), (2.5) and (2.6) below.

Swift Current: ARMA (4,3):

$$\begin{aligned} y_t =& 1.1772 y_{t-1} + 0.1001 y_{t-2} - 0.3572 y_{t-3} + 0.0379 y_{t-4} \\ &+ \alpha_t - 0.5030 \alpha_{t-1} - 0.2924 \alpha_{t-2} + 0.1317 \alpha_{t-3} \end{aligned} \tag{2.3}$$

$$\alpha_t \in NID(0, 0.524760^2)$$

Regina: ARMA (4,3):

$$\begin{aligned} y_t =& 0.9336 y_{t-1} + 0.4506 y_{t-2} - 0.5545 y_{t-3} + 0.1110 y_{t-4} \\ &+ \alpha_t - 0.2033 \alpha_{t-1} - 0.4684 \alpha_{t-2} + 0.2301 \alpha_{t-3} \end{aligned} \tag{2.4}$$

$$\alpha_t \in NID(0, 0.409423^2)$$

Saskatoon: ARMA (3,2):

$$\begin{aligned} y_t =& 1.5047y_{t-1} - 0.6635y_{t-2} + 0.1150y_{t-3} \\ &+ \alpha_t - 0.8263\alpha_{t-1} + 0.2250\alpha_{t-2} \end{aligned} \tag{2.5}$$

$$\alpha_t \in NID(0, 0.447423^2)$$

North Battleford: ARMA (3,2):

$$\begin{aligned} y_t =& 1.7901y_{t-1} - 0.9087y_{t-2} + 0.0948y_{t-3} \\ &+ \alpha_t - 1.0929\alpha_{t-1} + 0.2892\alpha_{t-2} \end{aligned} \tag{2.6}$$

$$\alpha_t \in NID(0, 0.474762^2)$$

The ARMA time series models expressed in (2.3) to (2.6) provide a valid representation of the wind regimes and it can be used to predict the future wind speeds based on the known data. The simulation results are used in the system adequacy studies to create wind speed probability distributions.

2.3 Wind power generation model

The power output characteristics of WTG are quite different from those of conventional generating units. A conventional generating unit is generally represented by a simple two-state model or multi state model as discussed in Chapter 4. A conventional generating unit can produce its rated power output when the unit is operating in the up state. If the unit is operating in the down state the power output is zero. If the unit is operating in a derated state, the power output is somewhere between zero and the rated power. The electric power output of a WTG in the up state mainly depends on its performance characteristics, the efficiency of the generator and the wind regime. The wind speed characteristics have a major impact on the power output. The power output of the WTG varies non-linearly with the wind speed and is illustrated graphically by the "power curve" in Figure 2.2.

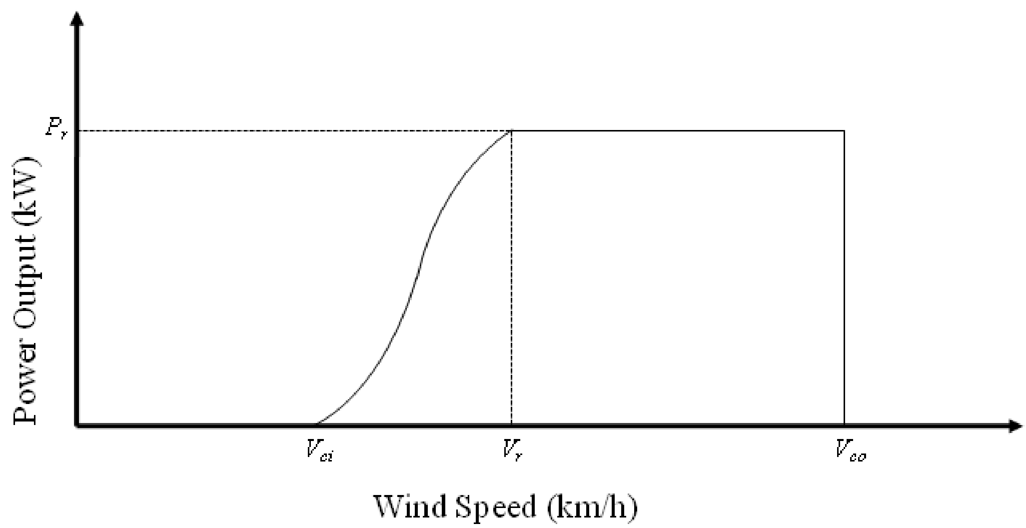

Figure 2.2: Wind turbine generator power curve.

The parameters commonly used are the cut-in wind speed, the rated wind speed and the cut-out wind speed. The WTG starts to generate power at the cut-in wind speed V_{ci}. The generated power increases non-linearly with increase in the wind speed from V_{ci} to the rated wind speed V_r, at which point it generates its rated power. The WTG is shut down for safety reasons when the wind speed exceeds the cut-out wind speed V_{co}. The hourly power output of a WTG at a specific time can be obtained from the simulated hourly wind speed using (2.7) [19].

$$P(SW_t) = \begin{cases} 0 & 0 \leq SW_t < V_{ci} \\ (A + B \times SW_t + C \times SW_t^2) \times P_r & V_{ci} \leq SW_t < V_r \\ P_r & V_r \leq SW_t < V_{co} \\ 0 & SW_t \geq V_{co} \end{cases} \tag{2.7}$$

where P_r, V_{ci}, V_r and V_{co} are the rated power output, the cut-in wind speed , the rated wind speed and the cut-out wind speed of the WTG. The constants A, B and C can be obtained using (2.8), (2.9) and (2.10).

$$A = \frac{1}{(V_{ci} - V_r)^2} \left\{ V_{ci}(V_{ci} + V_r) - 4V_{ci}V_r \left[\frac{V_{ci} + V_r}{2V_r} \right]^3 \right\} \tag{2.8}$$

$$B = \frac{1}{(V_{ci} - V_r)^2} \left\{ 4(V_{ci} + V_r) \left[\frac{V_{ci} + V_r}{2V_r} \right]^3 - (3V_{ci} + V_r) \right\} \tag{2.9}$$

$$C = \frac{1}{(V_{ci} - V_r)^2} \left\{ 2 - 4 \left[\frac{V_{ci} + V_r}{2V_r} \right]^3 \right\} \tag{2.10}$$

Cut-in, rated and cut-out wind speeds of 14.4, 36 and 80 km/hr respectively for a 2.0 MW WTG are used in the studies described in this thesis unless specifically noted otherwise.

2.4 Reliability Test System

The test system used in this research work is the Roy Billinton Test System RBTS [17].

The RBTS is a basic reliability test system evolved from the educational and research programs conducted at the University of Saskatchewan. It is a small composite system which provides the opportunity to conduct a large number of reliability studies with reasonable solution time. The RBTS has 11 conventional generating units with a total installed generating capacity of 240 MW. The annual peak load for the system is 185 MW.

The reliability data required at HL-1 for the test system are given in Table 2.2 which show the generation data for the RBTS. The load model data are shown in Tables 2.3, 2.4 and 2.5.

Table 2.2: Generating unit reliability data for the RBTS

Unit size (MW)	Type	Number of Units	Forced outage rate	MTTF (hr)	Failure rate per year	MTTR (hr)	Repair rate per year	Scheduled maintenance (wk/yr)
5	Hydro	2	0.010	4380	2.0	45	198.0	2
10	Thermal	1	0.020	2190	4.0	45	196.0	2
20	Hydro	4	0.015	3650	2.4	55	157.6	2
20	Thermal	1	0.025	1752	5.0	45	195.0	2
40	Hydro	1	0.020	2920	3.0	60	147.0	2
40	Thermal	2	0.030	1460	6.0	45	194.0	2

2.4.1 Load model

A daily peak load model of 364 days can be obtained by combining the weekly peak load in percent of the annual peak and the daily peak load in percent of the weekly peak (i.e. Tables 2.4 and 2.5 respectively). A daily peak load variation curve (DPLVC) can be obtained by arranging the daily peak load values in descending order. It is usually developed for a period of one year. The daily peak load variation curve is used extensively due to its simplicity. A load duration curve or hourly load model can be obtained by combining the weekly peak load in percent of the annual peak and the daily peak load in percent of the weekly peak and the hourly peak load in percent of the daily peak (i.e. Tables 2.3, 2.4 and 2.5 respectively). A load duration curve (LDC) can be obtained by arranging the hourly load values in descending order. The per unit load duration curve provides a more complete representation of the actual system load demand in comparison with the daily peak load variation curve. The per unit LDC and DPLVC for the RBTS is shown in Appendix A (Figure A.1).

Table 2.3: Hourly peak load in percent of daily peak

Hour	Winter Weeks 1 - 8 & 44 - 52		Summer Weeks 18 - 30		Spring/Fall Weeks 9 - 17 & 31 - 43	
	Wkdy	Wknd	Wkdy	Wknd	Wkdy	Wknd
12-1am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-Noon	95	91	100	93	99	94
Noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

Table 2.4: Daily peak load in percent of weekly peak

Day	Peak Load
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table 2.5: Weekly peak load in percent of annual peak

Week	Peak Load	Week	Peak Load
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.2

2.5 Building multi-state generating unit models using the Apportioning method

A generating unit can reside in many derated states in the course of its operating history [17, 18, 20]. The requirement is to represent the generating unit by a 'single-derated-state' model. The state reduction method is based on apportioning the residence times of the actual derated states between the assigned derated state and the up (normal) or down (outage) states. This method can be used to create specified multi-state models for a WTG and the WECS model. Figures 2.3 to 2.5 and the concepts used in this method are explained below. In these figures, X_N and Y_N are the original and designated derated states, respectively. $Y_{dn}(0)$ and $Y_{up}(100)$ are the full forced out and full capacity in states, respectively. The values within the brackets in the x-axis represent the percent capacity in service.

The procedure used to establish the "single-derated state" generating unit model shown in Figure 2.4 is as follows. Assume $Y_1 \leq X_N \leq Y_{up}$

$$\Delta_x t(Y_1)_N = \frac{Y_{up} - X_N}{Y_{up} - Y_1} \Delta_x t_N \tag{2.11}$$

$$\Delta_x t(Y_{up})_N = \frac{X_N - Y_1}{Y_{up} - Y_1} \Delta_x t_N \tag{2.12}$$

And when $X_N \leq Y_1 \leq Y_{up}$

$$\Delta_x t(Y_1)_N = \frac{X_N - Y_{dn}}{Y_1 - Y_{dn}} \Delta_x t_N \tag{2.13}$$

$$\Delta_x t(Y_{dn})_N = \frac{Y_1 - X_N}{Y_1 - Y_{dn}} \Delta_x t_N \tag{2.14}$$

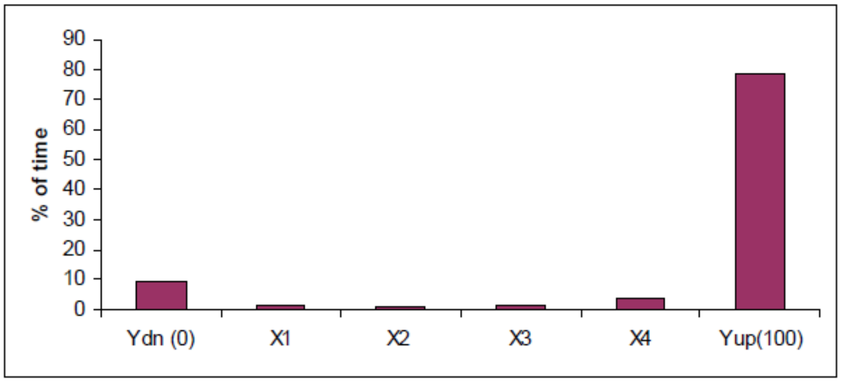

Figure 2.3: A two-state generating unit model containing no derated states [18]

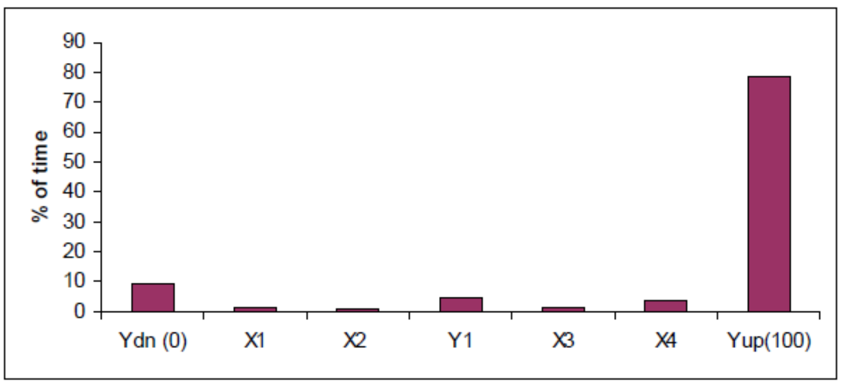

Figure 2.4: The "single-derated state" generating unit model [18]

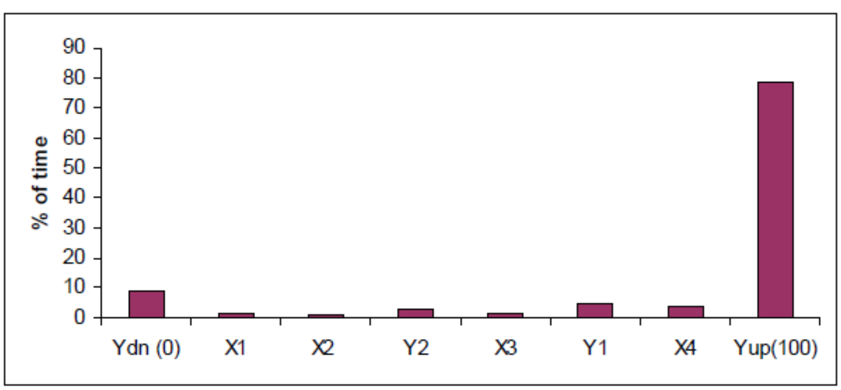

Figure 2.5: The "two-derated state" generating unit model [18]

P_{DN}, P_{UP} and P_{DE} are obtained as follows:

$$P_{DN} = \frac{T_{dn} + \sum_{n=1}^{n} \Delta(Y_{dn})_N}{T} \tag{2.15}$$

$$P_{UP} = \frac{T_{dn} + \sum_{n=1}^{n} \Delta_x t(Y_{up})_N}{T} \tag{2.16}$$

$$P_{DE} = \frac{\sum_{n=1}^{n} \Delta_x t(Y_1)_N}{T} \tag{2.17}$$

The procedure used to establish the "two-derated state" generating unit model shown in Figure 2.5 is as follows:

Assume $Y_1 \geq Y_2$

When $Y_1 \leq X_N \leq Y_{up}$

$$\Delta_x t(Y_1)_N = \frac{Y_{up} - X_N}{Y_{up} - Y_1} \Delta_x t_N \tag{2.18}$$

$$\Delta_x t(Y_{up})_N = \frac{X_N - Y_1}{Y_{up} - Y_1} \Delta_x t_N \tag{2.19}$$

When $X_N \leq Y_2 \leq Y_{up}$

$$\Delta_x t(Y_2)_N = \frac{X_N - Y_{dn}}{Y_2 - Y_{dn}} \Delta_x t_N \tag{2.20}$$

$$\Delta_x t(Y_{dn})_N = \frac{Y_2 - X_N}{Y_2 - Y_{dn}} \Delta_x t_N \tag{2.21}$$

When $Y_2 \leq X_N \leq Y_1$

$$\Delta_x t(Y_1)_N = \frac{X_N - Y_2}{Y_1 - Y_2} \Delta_x t_N \tag{2.22}$$

$$\Delta_x t(Y_2)_N = \frac{Y_1 - X_N}{Y_1 - Y_2} \Delta_x t_N \tag{2.23}$$

Where

X_N	$=$	N^{th} original derated state capacity in percent of full capacity
Y_N	$=$	N^{th} designated derated state capacity in percent of fully capacity
$Y_{dn}(0)$	$=$	Generating unit in the down state
$Y_{up}(100)$	$=$	Generating unit in the up state
N	$=$	Number of derated states (1,2,3,4 ...)
$\Delta_x t_N$	$=$	Residence time of the original derated state of X_N
$\Delta_x t(Y_1)_N$	$=$	Apportioned time of the determined derated state Y_1 for original derated state of X_N
$\Delta_x t(Y_2)_N$	$=$	Apportioned time of the determined derated state Y_2 from the original derated state of X_N
$\Delta_x t(Y_{up})_N$	$=$	Apportioned time of the up state from the original derated state of X_N
$\Delta_x t(Y_{dn})_N$	$=$	Apportioned time of the down state from the original derated state of X_N
T	$=$	Total time spent in the up, derated and down states
T_{up}	$=$	Time spent in the up state
T_{dn}	$=$	Time spent in the down state
$PFOR_{Xn}$	$=$	The partial forced outage rate for the N^{th} original derated state capacity in percent of full capacity
P_{DN}	$=$	Probability of the generating unit in the down state
P_{UP}	$=$	Probability of the generating unit in the up state
P_{DE}	$=$	Probability of the generating unit in the ith determined derated state

$$\Delta_x t_N = PFOR_{Xn} \times T \tag{2.24}$$

P_{DN} and P_{UP} can be obtained by using (2.15) and (2.16). P_{DE1} and P_{DE2} can be obtained by using (2.25) and (2.26).

$$P_{DE1} = \frac{\sum_{n=1}^{n} \Delta_x t(Y_1)_N}{T} \tag{2.25}$$

$$P_{DE2} = \frac{\sum_{n=1}^{n} \Delta_x t(Y_2)_N}{T} \tag{2.26}$$

The derating adjusted forced rate (DAFOR) [21] is the probability of a unit residing in the full down state. The term DAFOR is used by Canadian electric power utilities. In the United States, the designation for this statistic is the 'equivalent forced outage rate' (EFOR). The EFOR or DAFOR is determined using the apportioning method where the residence times of the actual derated states are apportioned between the up (normal) and down (outage) states. Here, there are no assigned derated states. The DAFOR of a generating unit can be obtained using (2.27) below.

$$\text{DAFOR} = P_{DN} + \sum_{i=1}^{n} \frac{\text{Cap.Cur}i}{\text{Cap}} \times P_{DEi} \tag{2.27}$$

Where

DAFOR = Derating-adjusted forced outage rate

P_{DN} = Probability of the generating unit in the down state

Cap.Cur$i$ = Curtailed capacity of the generating unit in the i^{th} derated state

Cap = Full capacity of the generating unit

P_{DEi} = Probability of the generating unit in the i^{th} derated state

n = the number of generating unit derated states

The hourly mean wind speeds for a WTG unit are developed using the relevant ARMA time series model. The hourly wind speed is applied to the power curve to obtain the output power for the WTG unit without considering it's forced outage rate (FOR). A capacity outage probability table (COPT) can be obtained by using the hourly wind speed and power output data and the following procedure.

1. Divide the output states of a WTG unit into segments of the rated power.

2. Determine the number of times the wind power results fall within each of the power output states.

3. Divide the number of occurrences by the total number of data points in order to estimate the probability of each state.

A COPT can be developed by following the above approach for each wind site. Table 2.6 shows the multi-state WTG COPT for the Swift Current site. The effect of WTG FOR is not included in this table. The DAFOR is the same for each multi-state capacity outage probability table in Table 2.7. The graphs in Figure 2.6 show the probably distributions of the annual power output for two simulated years for the Swift Current site.

The generating system including the wind energy generation model is then combined with the load model in order to obtain the risk model by using the techniques described in Chapter 4. Many reliability indices such as LOLE, LOEE, UPM, SM and EIR can be determined as discussed in Chapter 4.

Table 2.6: Multi-state WTG COPT

2-state		3-state		4-state		5-state		6-state	
Capacity Outage	Probability	Capacity Outage	Probability	Capacity Outage	Probability	Capacity Outage	Probability	Capacity Outage	Probability
0	0.26969	0	0.114024	0	0.114024	0	0.098435	0	0.074860
20	0.73031	10	0.311324	4	0.190686	4	0.103905	4	0.047150
		20	0.574652	10	0.301595	8	0.140575	8	0.080330
				20	0.393695	12	0.263390	12	0.140575
						20	0.393695	16	0.263390
								20	0.393695

7-state		8-state		9-state		10-state		11-state	
Capacity Outage	Probability	Capacity Outage	Probability	Capacity Outage	Probability	Capacity Outage	Probability	Capacity Outage	Probability
0	0.065940	0	0.065940	0	0.06594	0	0.06594	0	0.30248
4	0.017840	4	0.017840	2	0.01784	2	0.01784	2	0.18243
8	0.038230	6	0.038230	4	0.03823	4	0.02317	4	0.12602
12	0.080330	8	0.080330	6	0.08033	6	0.03012	6	0.09231
16	0.140575	12	0.094420	8	0.09442	8	0.06527	8	0.06846
18	0.263390	16	0.092310	12	0.09231	12	0.09442	10	0.05192
20	0.393695	18	0.217235	16	0.12602	14	0.09231	12	0.03931
		20	0.393695	18	0.18243	16	0.12602	14	0.03012
				20	0.30248	18	0.18243	16	0.02317
						20	0.30248	18	0.01784
								20	0.06594

DAFOR=0.73031

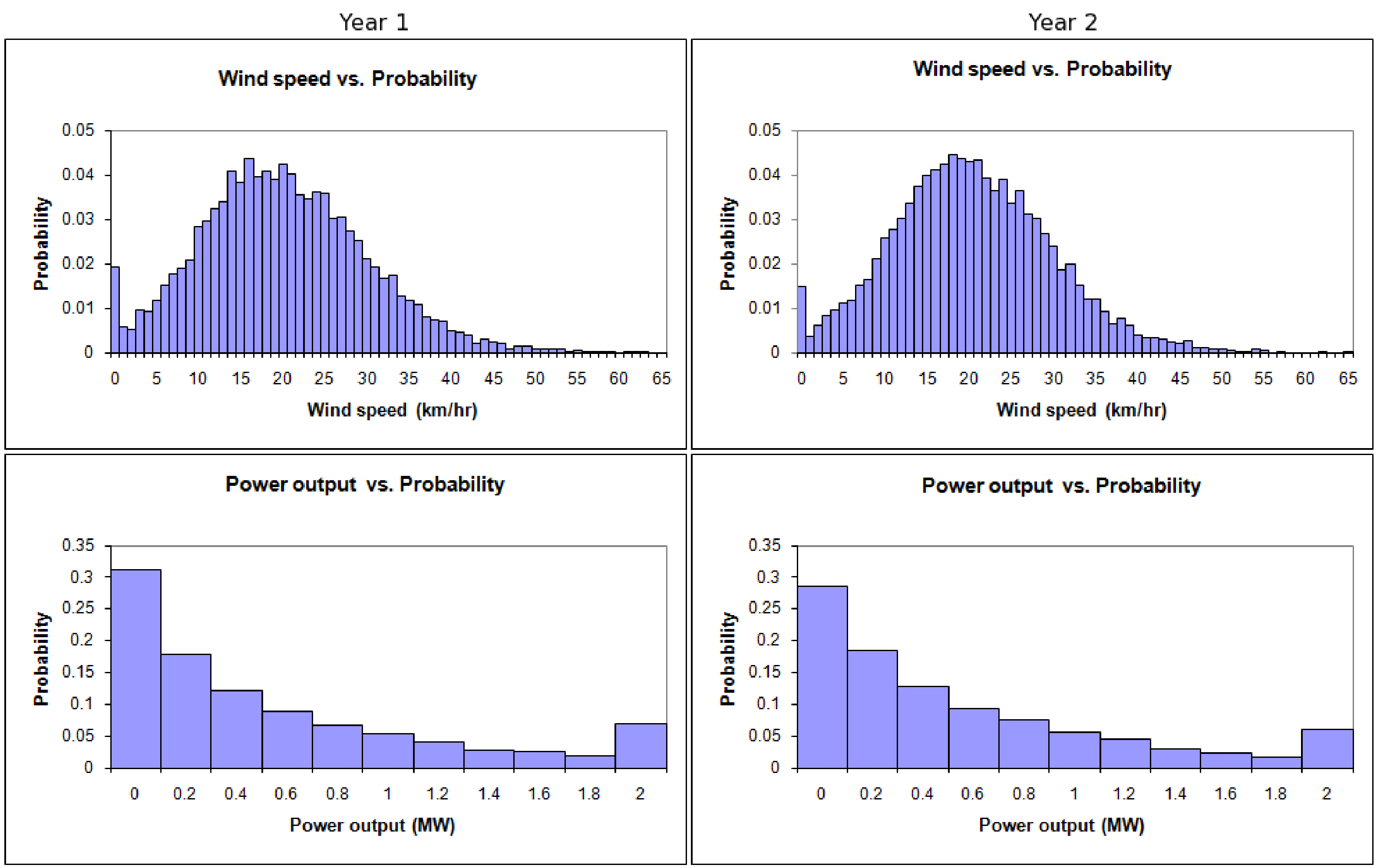

Figure 2.6: Probability distribution of annual wind speeds (top) and annual power outputs (bottom) for two simulated years.

2.6 Summary

The wind is the most mature green energy source in electric power systems. Wind power applications are growing steadily throughout the world in order to reduce environmental degradation. The basic model for generating capacity adequacy evaluation incorporating wind energy is described in this chapter. The ARMA time series model used in this research work for simulation of wind speeds is presented in this chapter. The power available from a WTG can be obtained from the simulated wind speed using a function describing the relationship between the wind speed and power output. The power output of a WTG is dependent on the wind regime and will increase if the facilities are located at a site where wind velocities are higher. An apportioning method is illustrated in this chapter that has been used for development of multistate WTG models. In this research work, the assumption is made that a WECS consists of multiple identical WTG units with zero FOR. A WECS multistate model is the same as that of a single WTG unit when the FOR of each WTG unit is zero and the DAFOR is the same for single WTG units and for the WECS.

Chapter 3

Capacity Credit Assessment using Time Period Analysis

3.1 Introduction

Wind energy is one of the fastest growing electrical energy sources. As noted in Chapter 2, wind power is considered to be a promising and encouraging alternative for power generation because of its tremendous environmental and social benefits along with public and government support. Wind is variable, site specific and a renewable source of energy and has a capacity value. It is hard to predict the behavior of wind and therefore the evaluation of capacity credit provided by wind energy is an interesting problem. The capacity credit of a renewable plant is defined as the amount of conventional resources (mainly thermal) that could be replaced by renewable production without making the system less reliable [22, 23]. Various methods used for evaluations of capacity credit are discussed in this chapter. The most accurate way to evaluate WECS capacity credit is to use probabilistic methods, based on a system load duration curve [23]. This method is best suited for system planners. The basic principles underlying probabilistic methods to assess the capacity credit of a wind plant are standard techniques normally used to evaluate the reliability of a power system. Probabilistic methods can be subdivided into two groups.

1. Analytical methods
2. Simulation methods

In analytical methods, mathematical and statistical models are used to represent the system elements. The system risk indices are obtained by solving mathematical models. In simulation methods, the actual process and the random behavior of the system is simulated. The reliability indices are obtained by observing the simulated operating history of the system.

There are various methods used to calculate the capacity value of a WECS. The effective load carrying capability (ELCC) is considered to be the preferred metric for evaluating the capacity value of a wind farm. The original concept of effective load carrying capability of a generating unit was introduced by L.L. Garver, in 1966 [24]. This basic method for calculating the capacity credit of wind power has been discussed by several authors [25]. The ELCC is typically calculated using a power system reliability model and the conventional ELCC calculation requires substantial reliability modeling. It is an iterative process and is computationally intensive. The Non-iterative method deals with minimal reliability modeling and is computationally less intensive than the conventional approach [19]. Since calculation of ELCC involves considerable data and computational effort, some NERC regions such as the Pennsylvania-New Jersey-Maryland (PJM) and Southwest Power Pool (SPP) use Approximate methods to calculate wind capacity credit. These Approximate methods are useful when the ELCC cannot be determined due to data or other limitations. Some of the Approximate methods used in the United States are as follows [26].

In the PJM method, the capacity credit is calculated based on the wind generator's capacity factor during the hours from 3 PM to 7 PM, from June 1 through August 31. The capacity credit is a rolling three year average, with the most recent year's data replacing the oldest year data [26].

The New York Independent System Operator (NYISO) determines wind capacity credit using the wind generator's capacity factor between 2 PM and 6 PM from June through Aug and 4 PM through 8 PM from December through February [26]. The California Public Utilities Commission (CPUC) uses a three year rolling average of the monthly average wind energy generation between 12 PM and 6 PM for the months of May through September [26]. The Public Service of New Mexico (PNM) utilizes the wind capacity factor during its peak time between 4 PM and 5PM during July [26]. The Southwest Power Pool (SPP) looks at the wind capacity factor during the peak hours of each month. The top 10% of the load hours are then ranked and the 85th percentile is calculated and considered to be the wind capacity value for the month. This process is then repeated for each month of the year [26]. Idaho Power determines the capacity factor during its peak time between 4 PM and 8 PM during July [26]. The California Energy Commission (CEC) uses a 3 year period capacity factor for the peak period defined by the California ISO [26]. Pacific Corp uses a sequential Monte Carlo (20%) method for evaluation of wind capacity credit [26]. Xcel also uses a sequential Monte Carlo (26-34%) method for evaluation of wind capacity credit [26].

The Chronological method is another approach for evaluating capacity credit [23]. This method is based on the WECS capacity factor (ratio between average and total possible output) over some relevant time period. In this method, the hourly load demands are arranged in a decreasing order. The WECS capacity factor is computed chronologically against the hourly load demand. Then the value of the capacity factor computed for the top 50% of the load hours is considered as an estimate of the WECS capacity credit. This method is best suited for system operators. The two time series analytical approches for wind capacity credit assessment utilized by the SPP and PJM are illustrated by application in the following sections.

3.2 Southwest Power Pool method

The Southwest Power Pool (SPP) is a Regional Transmission Organization (RTO) with 48 members who provide generation and transmission facilities and serve load. Members are investor-owned utilities (IOUs), municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers and an independent transmission coordinator. The SPP region covers 255,000 square miles and the eight south-western states of: Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma and Texas. Approximately 15% of the total electric load in Texas are served by SPP members and over 4.5 million consumers. It has 17 balancing authorities and control areas. Balancing authorities in the control areas have the responsibility of providing a continuous supply of electricity by balancing supply/demand [27]. The control area load and hourly wind production data should be known in order to determine the capacity credit of wind power. The top 10% of the load hours for the respective month and the corresponding wind production associated with each hour are used. The value that indicates that 85% of the time that capacity value or higher was present in the top 10% of the hours in the last five years is determined. This value can be obtained by using the ”percentile” function in Microsoft Excel and searching for the 0.15 value. This provides a capacity value which is expected for 85% or more of the time in the month. This can be repeated for each month and a different capacity value obtained for each month. This procedure is considered to provide a dependable wind capacity value with reliable service to consumers [28]. The load model data are shown in tables 2.3, 2.4 and 2.5. Hourly load model can be obtained by combining the weekly peak load in percent of the annual peak and the daily peak load in percent of the weekly peak and hourly peak load in percent of the daily peak (i.e tables 2.3, 2.4 and 2.5 respectively).

A year of load data was taken into consideration to examine this method. Out of which a single month, say the month of June and a single simulated year of data is chosen. There are 720 hourly load data points in the month of June. Out of these 720 data points, the top 10% i.e. 72 load data points are considered.

Column 2 in Table 3.1 presents the June load data values in an ordered manner (top 10%). The corresponding load hours associated with this load data are shown in column 3. The corresponding wind speed and wind power data values associated with those particular hours are shown in. columns 4 and 5 respectively in Table 3.1. The power data in column 5 are arranged in a descending order in column 6 in Table 3.1. As noted earlier, the capacity value of the 85th percentile is taken as the wind capacity credit for that particular month. The 85th percentage value for the 72 load data is 62. The 62 associated number wind power value is therfore the wind capacity credit for that particular month.

The wind Capacity Credit for the month of June in the given year for a 20 MW WECS at the Swift Current Site is 3.412 MW. The rated wind farm capacity is 20 MW. The capacity credit is therefore 17.06 percent. As discussed earlier, the SPP uses a criterion value of 85%. Table 3.2 and Figure 3.1 show the wind capacity credit using different criterion values, in order to apprciate how the assigned capacity credit is influenced by the criterion value.

It can be seen the wind capacity credit increases as the criterion value decreases. It varies from a minimum value of 3.412 to a maximum value of 18.065 in MW and 17.06 to 90.325 in percent for criterion values of 10 to 85%. The 85% criterion value was used in the following study in which the wind capacity credit was calculated for each year considering the months of June, July and August for a five year period.

Table 3.1: Top 10% load and power data with corresponding hours for the month of June for the Swift Current site with a 20 MW wind farm.

Sl. No.	Top 10% June load data of the annual peak (p.u.)	Corresponding hours	June speed data (km/hr)	June power data (MW)	June power data in descending order (MW)
1	0.900	84	24.077	5.854	20.000
2	0.900	86	30.808	12.899	20.000
3	0.900	87	32.084	14.510	20.000
4	0.896	420	15.263	0.317	20.000
5	0.896	422	16.813	0.988	20.000
6	0.896	423	22.400	4.479	20.000
7	0.891	83	24.950	6.630	20.000
8	**0.891**	**85**	**27.233**	**8.853**	**18.065**
9	0.887	252	30.029	11.959	17.538
10	0.887	254	26.780	8.390	17.030
11	**0.887**	**255**	**29.124**	**10.908**	**16.645**
12	0.887	419	13.955	0.000	16.501
13	0.887	421	21.597	3.873	15.596
14	0.882	108	34.685	18.065	14.510
15	**0.882**	**110**	**33.678**	**16.645**	**14.142**
16	0.882	111	31.630	13.926	13.926
17	0.878	251	29.286	11.092	13.692
18	**0.878**	**253**	**28.510**	**10.219**	**13.634**
19	0.878	444	38.556	20.000	12.899
20	0.878	446	29.826	11.720	12.827
21	0.878	447	31.799	14.142	12.798
22	**0.873**	**107**	**39.100**	**20.000**	**12.779**
23	0.873	109	40.880	20.000	12.518
24	0.873	88	27.270	8.892	11.959
25	0.869	276	21.934	4.123	11.720
26	**0.869**	**278**	**30.725**	**12.798**	**11.310**
27	0.869	279	23.697	5.529	11.092
28	0.869	443	37.527	20.000	10.908
29	**0.869**	**445**	**33.955**	**17.030**	**10.905**
30	0.869	424	16.164	0.691	10.219
31	0.864	89	27.699	9.342	9.912
32	0.864	90	22.944	4.908	9.342
33	**0.864**	**132**	**26.026**	**7.643**	**8.892**
34	0.864	134	45.265	20.000	8.853
35	0.864	135	34.316	17.538	8.722
36	**0.861**	**588**	**26.351**	**7.961**	**8.390**
37	0.861	590	30.710	12.779	7.961
38	0.861	591	22.518	4.571	7.788
39	0.861	275	15.354	0.353	7.668
40	**0.861**	**277**	**12.734**	**0.000**	**7.643**
41	0.860	256	17.444	1.298	7.258
42	0.860	425	23.750	5.574	7.235
43	0.860	426	18.805	2.040	6.630
44	**0.860**	**468**	**25.600**	**7.235**	**6.600**
45	0.860	470	29.475	11.310	6.540
46	0.860	471	31.445	13.692	5.854
47	**0.856**	**112**	**26.052**	**7.668**	**5.651**
48	0.855	131	20.952	3.412	5.593
49	0.855	133	30.495	12.518	5.574
50	0.855	82	26.174	7.788	5.529
51	**0.852**	**587**	**20.146**	**2.868**	**5.464**
52	0.852	589	24.851	6.540	5.172
53	0.852	448	31.399	13.634	5.108
54	**0.852**	**467**	**23.620**	**5.464**	**4.908**
55	0.852	469	22.483	4.543	4.571
56	0.852	257	39.031	20.000	4.543
57	0.852	258	33.574	16.501	4.479
58	**0.852**	**300**	**37.035**	**20.000**	**4.382**
59	0.852	302	27.105	8.722	4.123
60	0.852	303	23.269	5.172	3.873
61	0.851	418	12.584	0.000	3.541
62	**0.847**	**113**	**22.276**	**4.382**	**3.412**
63	0.847	114	23.840	5.651	2.868
64	0.846	156	29.121	10.905	2.040
65	0.846	158	25.625	7.258	1.298
66	0.846	159	23.191	5.108	0.988
67	0.844	612	24.917	6.600	0.691
68	0.844	614	23.772	5.593	0.353
69	0.844	615	21.135	3.541	0.317
70	0.843	280	28.230	9.912	0.000
71	0.843	299	30.749	12.827	0.000
72	0.843	301	32.908	15.596	0.000

Table 3.2: Capacity credit for the month of June at the Swift Current site for different criterion values.

Criterion Value	CC (MW)	CC (%)
85	3.412	17.060
80	4.382	21.910
75	4.908	24.540
70	5.46	27.320
65	5.651	28.255
60	6.600	33.000
55	7.643	38.215
50	8.390	41.950
45	8.892	44.460
40	10.905	54.525
35	11.310	56.550
30	12.779	63.895
25	13.634	68.170
20	14.142	70.710
15	16.645	83.225
10	18.065	90.325

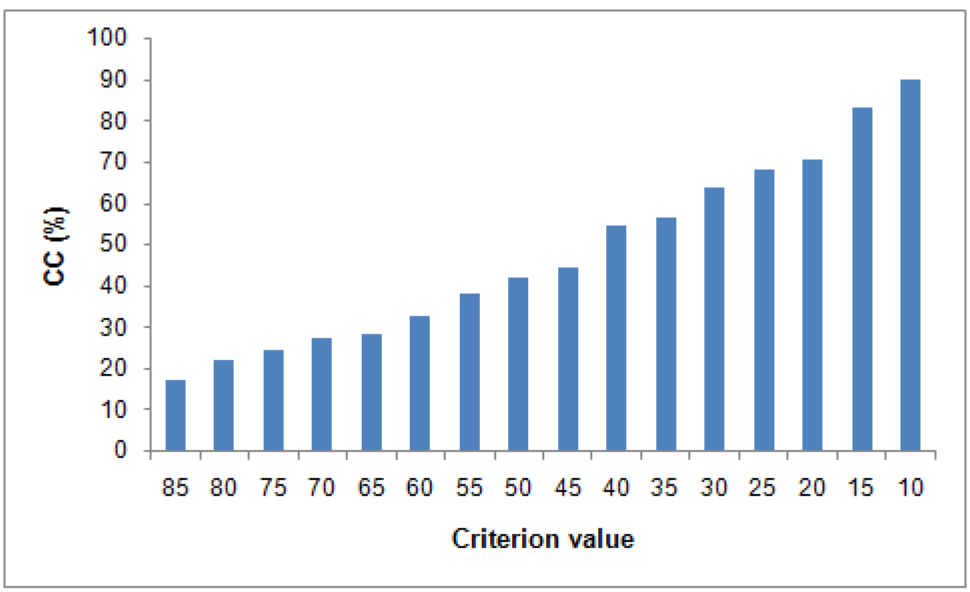

Figure 3.1: Capacity credit in percent vs. criterion value (Swift Curent, June)

The mean capacity credit was calculated for each year. The Table 3.3 shows the wind capacity credit for five individual years considering the months of June, July and August. The mean value noted in column 1 is the five year mean of each month. Column 5 shows the yearly mean of the three monthly values.

Table 3.3: Wind capacity credit for a 5 year period at the Swift Current site for the months of June, July and August.

Year	CC (%)			Mean CC (%)
	June	July	August	
1	0.000	0.000	0.000	0.000
2	17.061	0.000	0.000	5.687
3	11.597	0.000	0.000	3.866
4	1.028	0.000	0.000	0.343
5	0.000	0.000	0.000	0.000
Mean	5.937	0.000	0.000	-

It can be seen in Table 3.3 that the wind capacity credit value fluctuate each year. It varies from a minimum value of zero to a maximum value of 5.687%. It is also noted that in the months of July and August the capacity credit is zero. The average capacity credit for the months of June, July and August is 5.937%, zero and zero respectively for the five year period. Table 3.4 shows the wind capacity credit using a three year rolling average for the months of June, July and August for the Swift Current site.

Table 3.4: Wind capacity credit using a three rolling year average for the Swift Current site.

Starting Year	CC (%)		
	June	July	August
1	9.553	0.000	0.000
2	9.895	0.000	0.000
3	4.208	0.000	0.000

Three years of data were placed in a single data file (This method is designated as the pooled approach) for each month and the 85th percentage value taken as the capacity credit for the respective months. Table 3.5 shows the wind capacity credit considering three rolling years of pooled data for the months of June, July and August for the Swift Current site.

It can be seen from Table 3.5 that the capacity credit varies from a maximum value of 9.428% to a minimum value of 0.747% for the month of June. Zero capacity credit is obtained for the months of July and August.

Table 3.5: Wind capacity credit for three rolling years of pooled data for a 20 MW WECS at the Swift Current site.

Starting Year	CC (%)		
	June	July	August
1	4.710	0.000	0.000
2	9.428	0.000	0.000
3	0.747	0.000	0.000

The wind capacity credit was calculated by applying the Southwest Power Pool method to three consecutive years using the months of June, July and August data. The SPP uses a criterion value of 85%. The wind capacity credit was calculated for a range of criterion values. Table 3.6 and Figure 3.2 show the pooled capacity credits for different criterion values.

It can be seen in Table 3.6 that the mean wind capacity credit value for the three year period varies from a minimum value of 1.570 to a maximum value of 73.550 as the criterion value changes from 85 to 5%. The assigned wind capacity credit of several actual wind sites as discussed by the Southwest Power Pool generating group in a wind power capacity accreditation white paper [28] are shown below.

Blue Canyon - 5.5 MW (7.4%) (2 years data)

Gray County - 4.1 MW (3.7%) (1 year data)

White Deer - 7 MW (8.8%) (2 Years)

Woodward - 2 MW (4%) (1 year)

Table 3.6: Pooled wind capacity credit at the Swift Current site for different criterion values.

Criterion Value	CC (%)			Mean CC (%)
	June	July	August	
85	4.710	0.000	0.000	1.570
80	10.867	0.000	0.000	3.622
75	15.238	0.000	0.000	5.079
70	17.830	0.000	0.000	5.943
65	21.912	0.000	0.000	7.304
60	25.540	0.000	0.000	8.513
55	30.471	2.131	0.927	11.177
50	33.150	6.472	2.634	14.085
45	36.291	8.915	5.223	16.809
40	40.461	10.911	7.229	19.533
35	45.197	13.878	10.394	23.156
30	54.630	17.392	13.883	28.635
25	63.990	22.694	17.985	34.890
20	72.380	26.747	22.543	40.557
15	83.225	32.495	30.179	48.633
10	100.000	38.891	44.771	61.221
5	100.000	61.725	58.925	73.550

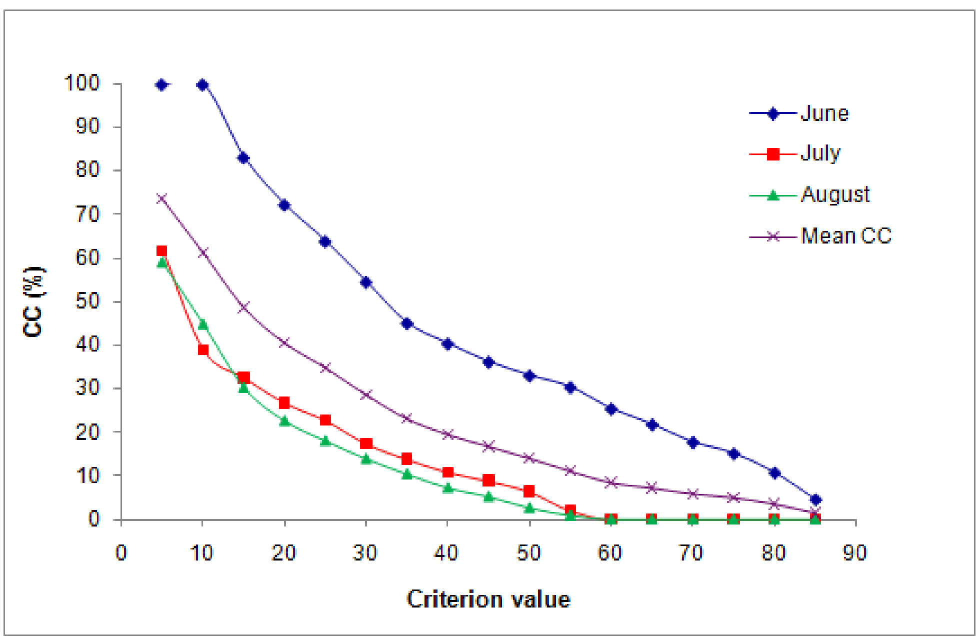

Figure 3.2: Capacity credit in percent vs. criterion value (Swift Curent, Pooled data)

3.2.1 Parameter variation analysis for different wind sites

The Southwest Power Pool method was also applied to the Regina, Saskatoon and North Battleford wind sites in Saskatchewan, Canada.

Tables 3.7, 3.8 and 3.9 show the wind capacity credit values for the Regina, Saskatoon and North Battleford sites respectively for 5 individual years considering the months of June, July and August. The mean values in column 1 are the average of five years of data for a single month. Column 5 presents the mean of the three month data.

Table 3.7: Wind capacity credit for 5 years at the Regina site for the months of June, July and August.

Year	CC (%)			Mean CC (%)
	June	July	August	
1	0.000	0.000	0.000	0.000
2	2.539	0.000	7.266	3.268
3	5.484	6.929	0.000	4.138
4	0.000	0.000	2.650	0.883
5	0.000	4.403	0.000	1.468
Mean	1.605	2.266	1.983	-

Table 3.8: Wind capacity credit for 5 years at the Saskatoon site for the months of June, July and August.

Year	CC (%)			Mean CC (%)
	June	July	August	
1	0.000	0.000	0.000	0.000
2	1.056	0.000	1.149	0.735
3	0.000	2.851	0.000	0.950
4	0.000	0.000	0.000	0.000
5	0.000	7.418	0.000	2.473
Mean	0.211	2.054	0.230	-

It can be seen that no capacity credit is assigned for the months of June, July and August for the North Battleford site using the SPP method. As noted earlier, the SPP uses a criterion value of 85%. Table 3.10 and Figure 3.3 show the wind capacity

Table 3.9: Wind capacity credit for 5 years at the North Battleford site for the months of June, July and August.

Year	CC (%)			Mean CC (%)
	June	July	August	
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
Mean	0	0	0	-

Table 3.10: Wind capacity credit at the North Battleford Site for the months of June, July and August at different criterion values.

Criterion Value	CC (%)			Mean CC (%)
	June	July	August	
85	0.000	0.000	0.000	0.000
80	0.000	0.000	0.000	0.000
75	0.000	0.000	0.000	0.000
70	0.000	0.000	0.000	0.000
65	0.000	0.000	0.000	0.000
60	0.000	0.811	0.000	0.270
55	0.054	2.041	0.000	0.698
50	0.972	5.737	0.000	2.236
45	2.132	7.733	0.247	3.371
40	3.789	11.036	4.409	6.411
35	4.276	14.198	10.713	9.729
30	5.296	18.310	12.249	11.952
25	9.240	25.269	18.342	17.617
20	10.962	31.739	25.487	22.729
15	14.940	43.346	36.905	31.730
10	15.469	67.980	59.640	47.696
5	22.538	96.580	76.030	65.049
Mean	5.274	19.105	14.354	-

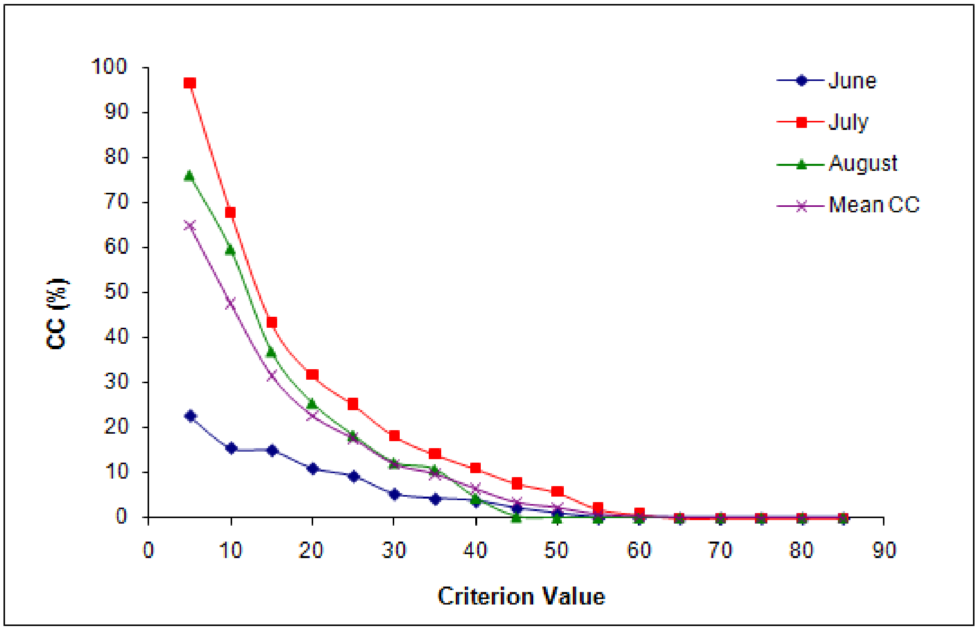

Figure 3.3: Capacity credit in percentage vs. criterion value (North Battleford, Pooled data)

credit for the North Battleford site for different criterion values for the months of June, July and August.

It can be seen that the wind capacity credit increases as the criterion value decreases. Figures 3.4, 3.5 and 3.6 present the wind capacity credit for the months of June, July and August respectively for the Swift Current, Regina, Saskatoon and North Battleford sites.

Table 3.11 shows the wind capacity credit considering five years of pooled data for the months of June, July and August for the four different sites.

The various studies show that in the month of June, Swift Current has the highest wind capacity credit for all the years followed by Regina, Saskatoon and North Battleford. For the month of July, both Regina and Saskatoon are found to be the better sites. Regina is better in the 3rd year than Saskatoon where as in the 5th year Saskatoon is better than Regina. In August the Regina site is better for all

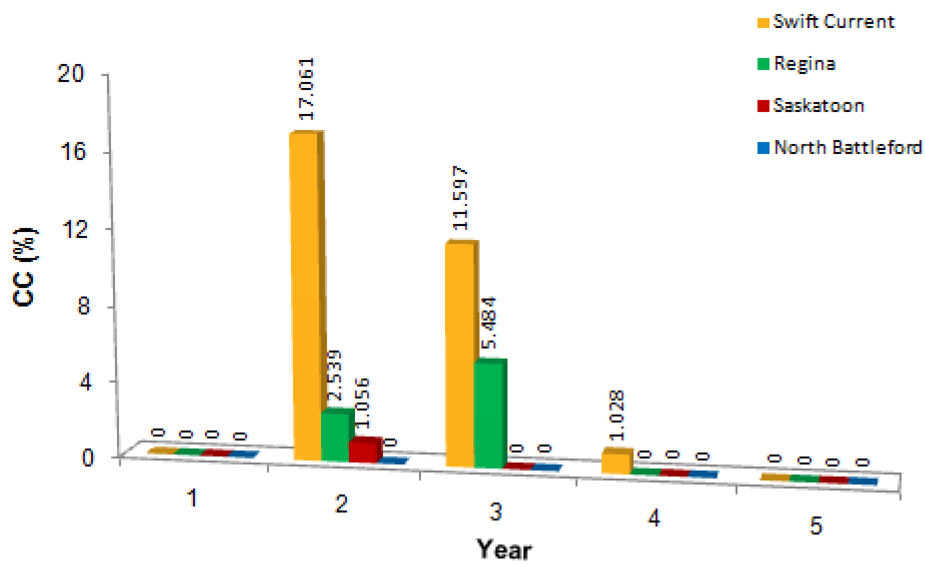

Figure 3.4: Wind capacity credit in percent vs year for the month of June.

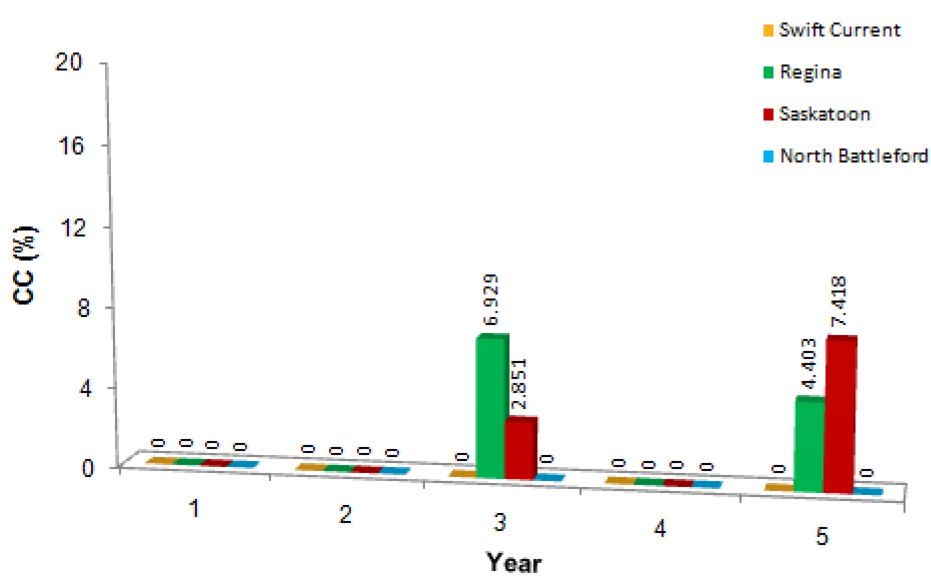

Figure 3.5: Wind capacity credit in percent vs year for the month of July.

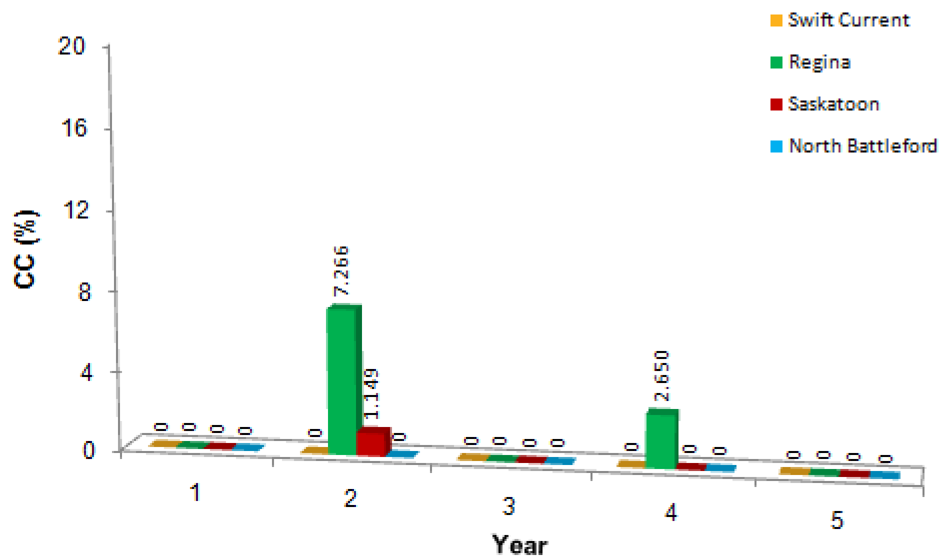

Figure 3.6: Wind capacity credit in percent vs year for the month of August.

Table 3.11: Wind capacity credit for 5 years of pooled data at the different sites for the months of June, July and August.

Site	CC (%)		
	June	July	August
Regina	0	0	0
Swift Current	1.6771	0	0
Saskatoon	0	0	0
North Battleford	0	0	0

the years. The assigned wind capacity credit clearly depends on which month and which site is chosen. As an example the Swift Current site is better in June where as in July and August its not. Similarly for August, Regina is better but for June it is not. The wind capacity credit is higher in certain individual years than in pooled years. The various studies clearly show how the wind capacity credit increases as the selected criterion value decreases.

3.2.2 Parameter variation analysis for the four wind sites using a modified WTG

As noted at the end of Section 2.3, a cut-in-speed of 14.4 km/hr, rated-speed of 36 km/hr and cut-out-speed of 80 km/hr for a 2 MW WTG in a 20 MW wind farm [20] (Figure 3.7) is used in the basic studies in this thesis. The A, B and C constant values described in Chapter 2 are 0.0311, -0.0215, 0.0013 respectively. The WTG rating was changed to a cut-in-speed of 7.2 km/hr, rated-speed of 34.2 km/hr and cut-out-speed of 90 km/hr [29] in order to examine the effect on the capacity credit values. The original and modified wind power curves are shown in Figure 3.7. The A, B and C constants in this case are 0.1093, -0.0262, 0.0015 respectively. The modified WTG values were applied to the different sites using the SPP method. Tables 3.12, 3.13, 3.14 and 3.15 show the wind capacity credit for 5 individual years using the months of June, July and August for Swift Current, Regina, Saskatoon and North Battleford respectively. Column 1 presents the mean of five years of a single month, whereas column 4 presents the mean of three months.

Figures 3.8, 3.9 and 3.10 present the wind capacity credit for the months of June, July and August respectively for four different Saskatchewan sites (Swift Current, Regina, Saskatoon and North Battleford).

Five years of data are placed in a single column (designated as pooled data)

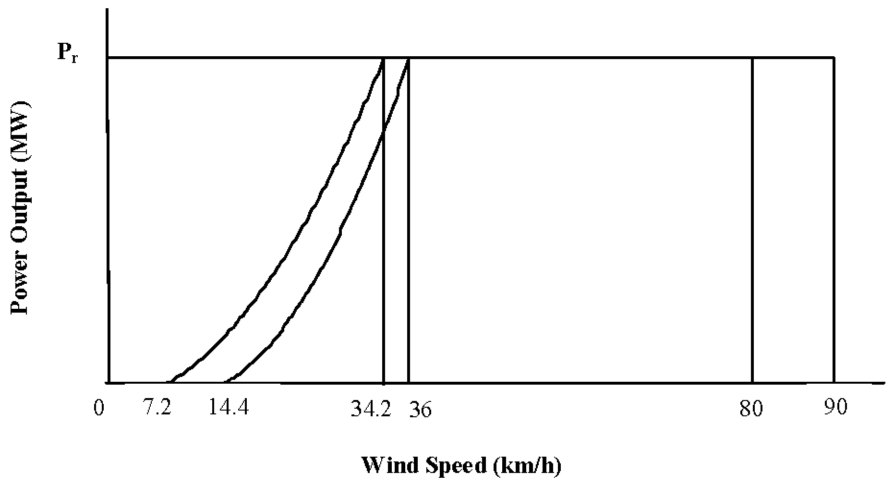

Figure 3.7: Modified WTG rating.

for each month and the 85th percent value is taken as the capacity credit for the respective months. Table 3.16 shows the wind capacity credit considering five years of pooled data for the months of June, July and August for the four different sites.

Table 3.12: Wind capacity credit for 5 years at the **Swift Current** site for the months of June, July and August.

Year	CC (%)			Mean CC (%)
	June	July	August	
1	0.953	0.000	0.000	0.318
2	23.115	0.000	1.039	8.051
3	17.207	3.405	0.000	6.871
4	5.967	0.000	0.315	2.094
5	1.612	0.869	0.267	0.916
Mean	9.771	0.855	0.324	-

3.2.3 Discussion

Wind capacity credit associated with 20 MW WECS at the Swift Current site calculated by using the South West Power Pool method for a year considering the month of June only is 3.412 in MW and 17.061 in percent. Wind capacity credit for

Table 3.13: Wind capacity credit for 5 years at the **Regina** site for the months of June, July and August.

Year	CC (%)			Mean CC (%)
	June	July	August	
1	2.355	0.000	0.000	0.785
2	7.549	0.000	12.561	6.703
3	10.662	12.201	0.000	7.621
4	3.427	1.926	7.665	4.339
5	0.288	9.515	3.641	4.481
Mean	4.856	4.729	4.773	-

Table 3.14: Wind capacity credit for 5 years at the **Saskatoon** site for the months of June, July and August.

Year	CC (%)			Mean CC (%)
	June	July	August	
1	0.000	0.000	0.000	0.000
2	5.996	0.000	6.093	4.030
3	3.453	7.876	0.000	3.776
4	2.364	2.683	3.245	2.764
5	0.000	12.723	2.463	5.062
Mean	2.363	4.657	2.360	-

Table 3.15: Wind capacity credit for 5 years at the **North Battleford** site for the months of June, July and August.

Year	CC (%)			Mean CC (%)
	June	July	August	
1	0.000	0.000	0.000	0.000
2	1.165	0.000	2.763	1.310
3	0.590	2.938	0.000	1.176
4	0.000	0.000	0.355	0.118
5	0.000	4.599	0.000	1.533
Mean	0.351	1.507	0.624	-

Table 3.16: Wind capacity credit for 5 years of pooled data for different sites for the months of June, July and August.

Site	CC (%)		
	June	July	August
Regina	3.816	1.160	2.336
Swift Current	6.645	0.000	0.000
Saskatoon	1.392	0.352	1.421
North Battleford	0.000	0.000	0.000

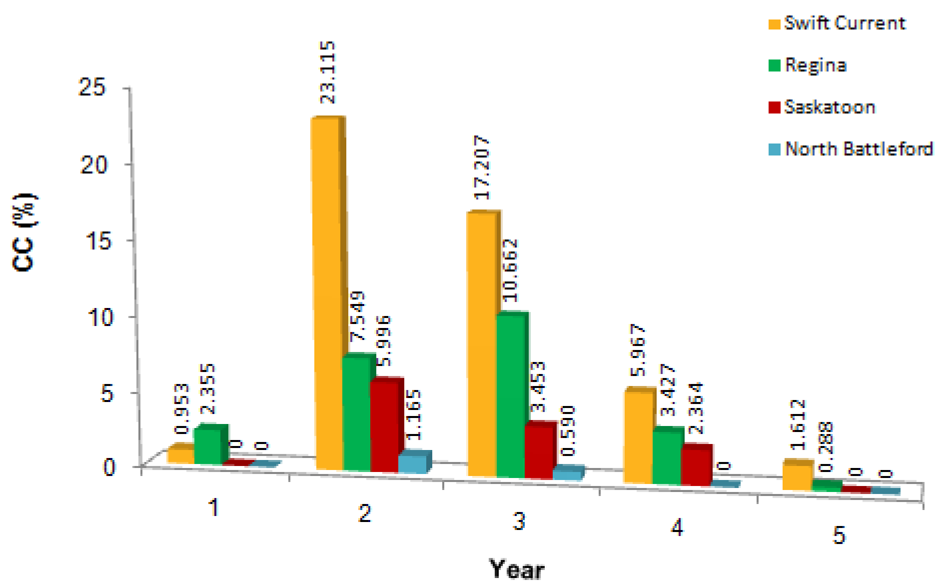

Figure 3.8: Wind capacity credit in percent vs year for the month of June.

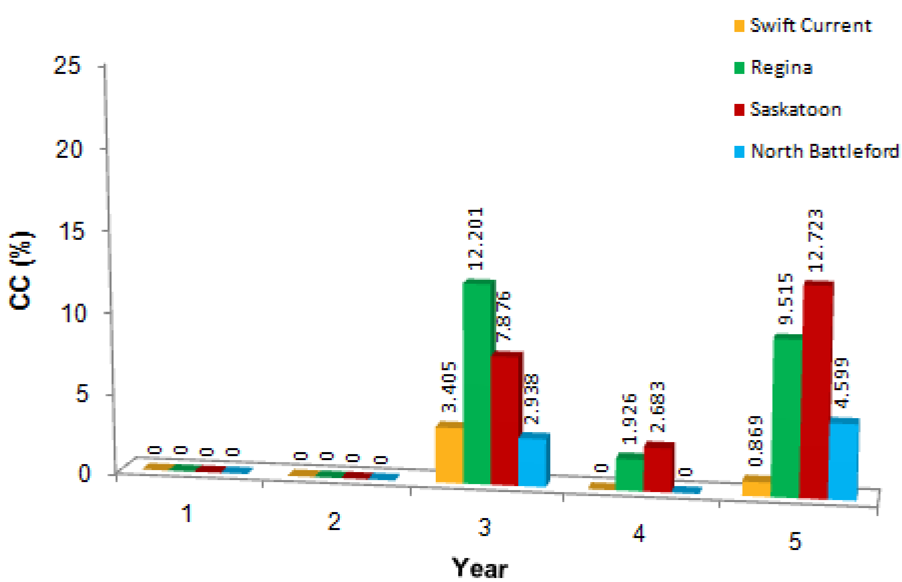

Figure 3.9: Wind capacity credit in percent vs year for the month of July.

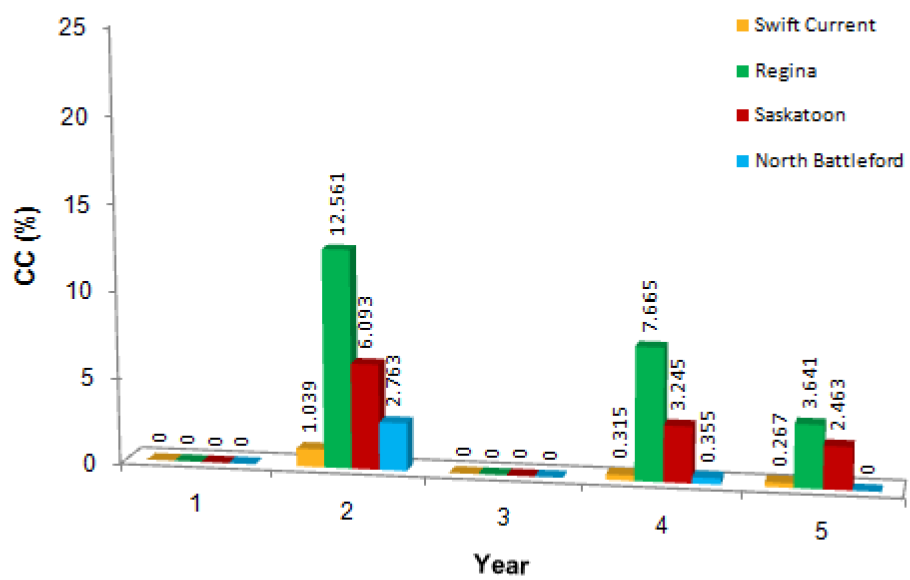

Figure 3.10: Wind capacity credit in percent vs year for the month of August.

the Swift Current site calculated for three years for the months of June, July and August is 0.314 MW i.e. 1.57 in percent. The capacity credit was also calculated for different percentages of time i.e. from 85 to 5%. It should be noted that as the percentage value decreases the capacity credit value increases. Three year rolling average wind capacity credit considering the months of June, July and August were calculated for the Swift Current site and vary from a minimum value of 4.208% to a maximum value of 9.553% for the month of June whereas in July and August no capacity credit is obtained. Using three rolled years of pooled data considering the months of June, July and August, the wind capacity credit varies from a maximum value of 0.9421 MW i.e. 9.428% to a minimum value of 0.1494 MW with 0.747% for the month of June, whereas for the month of July and August zero capacity credit is obtained. It is observed that a higher capacity credit value is obtained in the case of a three year rolling average in comparison to three years of pooled data. A rolling average reduces the volatility of annual values. The SPP wind capacity credit was calculated for each year up to five years considering the months of June, July and August. The results obtained range from minimum of zero to a maximum of 5.687 percent. It is also observed that each year the capacity credit value is different from the previous year using the 85th percent approach. In conclusion, the capacity credit value fluctuates widely from year to year. Using the modified WTG ratings (power curve characteristic) resulted in higher values of capacity credit at each site, for each year and for each month. It is concluded that the wind capacity credit is dependent on the WTG rating and comparatively higher capacity credit values are obtained for lower cut-in-value of WTG. It is also noted that in capacity credit evaluations some sites are better for a particular month while others are not and vice versa. In the month of June, the Swift Current site has the highest wind capacity credit followed by those at Regina, Saskatoon and North Battleford. For the month of July, both Regina and Saskatoon are found to be the better sites. Regina is better in the 3rd year than Saskatoon whereas in the 5th year Saskatoon is better than Regina. In August, the Regina site is better in June for all the years. The assigned wind capacity credit clearly depends on which month and which site is chosen. As an example, the Swift Current site is better in June whereas in July and August it's not. Similarly for August, Regina is better but for June it is not. It is also noted that the wind capacity credit is higher for individual years in comparison to that in pooled years.

3.3 PJM method

As noted earlier there are a number of methods to calculate the wind capacity values. The PJM is a well known mehod used for capacity credit evaluation. The PJM is a RTO that covers all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West

Virginia, and the District of Columbia. It has more than 56,000 miles of transmission lines, more than 1,000 generating units, more than 163,000 MW of capacity, and it serves about 131,000 MW of peak demand (PJM 2005) [30]. In the PJM method the capacity credit of wind is based on the wind generator's capacity factor during the hours from 3 PM to 7 PM, from June 1 through August 31. The capacity credit is a rolling three year average, with the most recent year's data replacing the oldest year data [26, 30]. Wind data is collected at different sites in this method. Synthetic hourly wind speed data for 100 years were generated using the ARMA time series model. Wind speed varies with time and site and it varies significantly from year to year and from hour to hour. The hourly power output can be easily obtained from the simulated hourly wind speeds using Equation (2.7).

Once the hourly wind speeds are obtained, the next step is to find the wind speeds within the specified time period i.e. from 1st of June to 31st of Aug for each year. June, July and August consist of 30, 31 and 31 days respectively and therefore there are 720,744 and 744 hourly wind speed values for a total of 2208 in each year. The hourly wind speeds from 3 PM to 7 PM are used in the analysis. The wind power outputs corresponding to these wind speeds within the time frames 3 PM to 7 PM from June 1st through Aug 31st are obtained for each year. The average power output is then calculated for each year. This process was repeated for 100 years. The PJM capacity credit is a rolling 3 year average with the most recent year's data replacing oldest year's data using the 100 years of data, 98 wind power capacity credit values were obtained in the form of 3 year rolling averages. Table 3.17 and Figure 3.11 show the wind capacity credit values for the Swift Current site.

Table 3.17: Wind capacity credit at the Swift Current site for a 98 year period using the PJM method.

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	24.957	34	26.784	67	26.361
2	26.923	35	28.160	68	24.905
3	27.972	36	26.242	69	25.027
4	26.909	37	24.489	70	22.927
5	27.382	38	24.109	71	24.011
6	26.608	39	23.817	72	23.845
7	29.258	40	23.543	73	25.702
8	25.970	41	23.929	74	25.230
9	25.137	42	25.458	75	26.615
10	23.343	43	26.789	76	26.528
11	25.926	44	25.711	77	25.385
12	27.202	45	24.966	78	23.301
13	26.465	46	26.269	79	23.948
14	26.217	47	27.181	80	25.265
15	27.250	48	26.405	81	25.527
16	28.469	49	24.925	82	24.831
17	28.638	50	23.931	83	23.592
18	26.483	51	23.574	84	23.677
19	26.276	52	22.709	85	23.612
20	26.118	53	23.437	86	24.109
21	25.095	54	27.514	87	24.577
22	23.636	55	26.809	88	24.024
23	22.646	56	27.516	89	24.727
24	23.004	57	24.353	90	24.601
25	23.898	58	25.904	91	25.298
26	21.095	59	25.899	92	26.452
27	21.759	60	26.560	93	26.368
28	22.282	61	28.306	94	25.855
29	23.743	62	27.192	95	25.089
30	23.527	63	27.175	96	26.407
31	24.517	64	26.368	97	25.991
32	25.201	65	27.874	98	26.216
33	27.110	66	27.157		

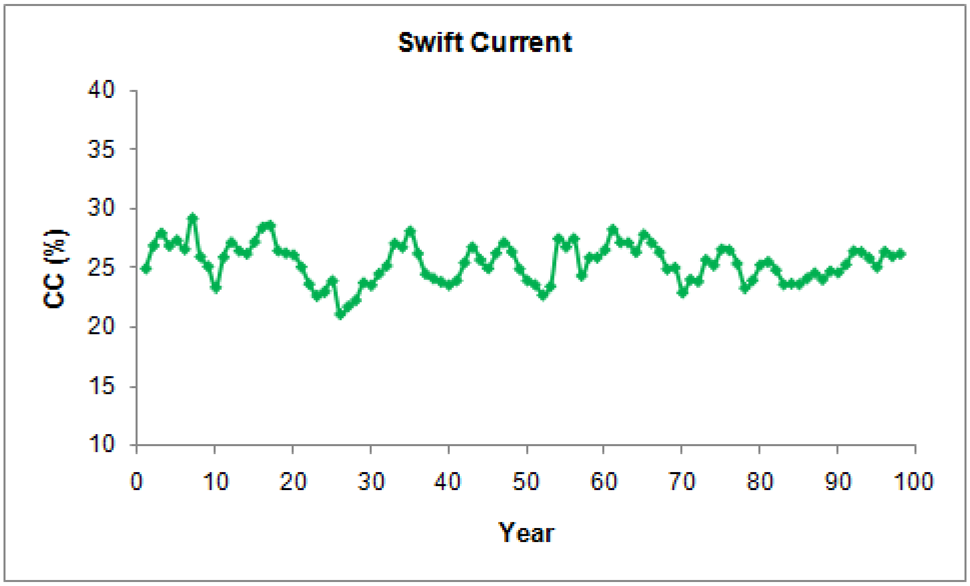

Figure 3.11: Capacity credit for the Swift Current site.

3.3.1 Parameter variation analysis for different wind sites

The PJM method was also applied to the Regina, Saskatoon and North Battleford sites. Tables 3.18, 3.19 and 3.20 and Figures 3.12, 3.13 and 3.14, show respectively, the wind capacity credit values for Regina, Saskatoon and North Battleford considering a three year rolling average for the months of June, July and August using 100 years of data. Figure 3.15 presents a comparison graph of the four different sites. Annual capacity credit tables and a comparision graph for the Regina and Swift Current sites in the month of July are shown in Appendix B.

Table 3.18: Wind capacity credit at the Regina site for a 98 year period using the PJM method.

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	31.503	34	34.312	67	34.165
2	33.993	35	35.374	68	31.997
3	35.144	36	33.837	69	31.127
4	35.034	37	31.697	70	29.027
5	35.499	38	31.432	71	29.987
6	35.444	39	30.769	72	30.477
7	38.128	40	30.391	73	33.068
8	34.251	41	31.349	74	32.909
9	32.360	42	33.123	75	34.891
10	29.904	43	34.608	76	35.054
11	32.853	44	33.251	77	33.690
12	34.616	45	31.908	78	31.244
13	33.901	46	33.635	79	31.053
14	33.764	47	35.101	80	32.656
15	35.052	48	34.152	81	32.731
16	36.236	49	32.194	82	31.872
17	36.468	50	30.864	83	30.216
18	33.436	51	31.030	84	30.736
19	32.907	52	30.583	85	30.321
20	33.250	53	30.979	86	31.174
21	32.018	54	34.925	87	31.473
22	30.101	55	34.043	88	31.872
23	28.660	56	35.701	89	32.056
24	29.714	57	32.414	90	31.403
25	30.999	58	33.962	91	31.964
26	27.425	59	33.426	92	33.691
27	28.384	60	34.474	93	33.480
28	29.165	61	35.759	94	32.247
29	31.125	62	34.621	95	32.548
30	30.987	63	34.503	96	34.427
31	31.569	64	34.265	97	34.682
32	32.033	65	36.136	98	34.286
33	33.960	66	35.345		

Table 3.19: Wind capacity credit at the Saskatoon site for a 98 year period using the PJM method.

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	21.575	34	23.743	67	23.392
2	23.398	35	24.457	68	21.340
3	24.984	36	23.478	69	20.938
4	24.557	37	21.606	70	19.618
5	24.758	38	21.452	71	20.955
6	24.350	39	20.849	72	21.152
7	26.678	40	20.972	73	23.091
8	23.654	41	21.532	74	23.005
9	21.758	42	23.110	75	24.830
10	19.957	43	24.030	76	24.978
11	22.274	44	23.414	77	23.482
12	24.228	45	22.206	78	21.558
13	23.434	46	23.891	79	21.546
14	23.824	47	24.807	80	22.891
15	25.039	48	24.548	81	22.454
16	26.176	49	22.849	82	21.480
17	26.605	50	21.963	83	20.296
18	24.268	51	21.447	84	21.086
19	23.369	52	20.845	85	20.875
20	22.927	53	20.968	86	21.321
21	21.872	54	24.816	87	21.723
22	20.669	55	24.033	88	21.978
23	19.583	56	25.254	89	22.427
24	20.043	57	22.024	90	21.880
25	21.015	58	23.235	91	22.487
26	18.176	59	23.038	92	23.763
27	18.785	60	23.565	93	23.390
28	19.681	61	24.736	94	22.615
29	21.491	62	23.657	95	22.928
30	21.420	63	23.947	96	24.501
31	21.988	64	23.648	97	24.510
32	22.267	65	25.246	98	24.162
33	23.654	66	24.471		

Table 3.20: Wind capacity credit at the North Battleford site for a 98 year period using the PJM method.

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	17.124	34	19.319	67	19.147
2	18.809	35	20.143	68	17.205
3	20.582	36	19.344	69	17.321
4	20.189	37	17.376	70	16.297
5	20.429	38	17.440	71	17.492
6	19.943	39	16.920	72	17.351
7	22.137	40	17.084	73	19.005
8	19.224	41	17.288	74	18.514
9	17.702	42	18.597	75	20.055
10	15.924	43	19.569	76	20.268
11	18.066	44	19.338	77	19.299
12	19.614	45	18.381	78	17.721
13	18.851	46	19.828	79	17.456
14	19.163	47	20.614	80	18.334
15	20.252	48	20.154	81	17.624
16	21.267	49	18.349	82	17.010
17	21.643	50	17.449	83	16.274
18	19.860	51	16.811	84	17.200
19	19.217	52	16.284	85	17.026
20	18.906	53	16.320	86	17.538
21	18.041	54	20.299	87	17.945
22	16.652	55	19.835	88	17.668
23	15.975	56	21.066	89	17.786
24	15.953	57	18.048	90	17.454
25	17.108	58	19.135	91	18.148
26	14.360	59	19.005	92	19.347
27	15.120	60	19.167	93	18.988
28	15.634	61	20.309	94	18.550
29	17.355	62	19.054	95	18.598
30	17.019	63	19.299	96	19.840
31	18.206	64	19.134	97	19.785
32	18.052	65	20.945	98	19.592
33	19.518	66	20.308		

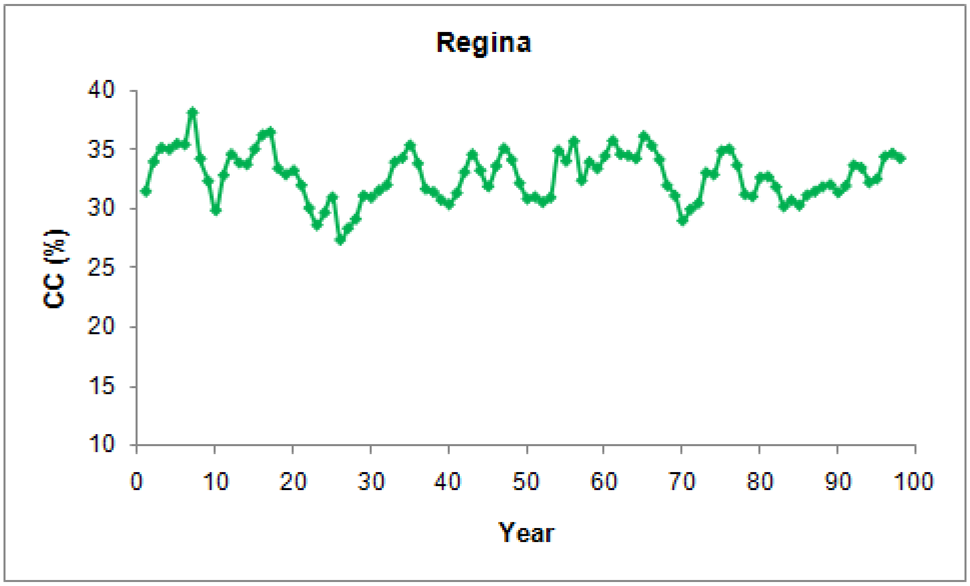

Figure 3.12: Capacity credit for the Regina site.

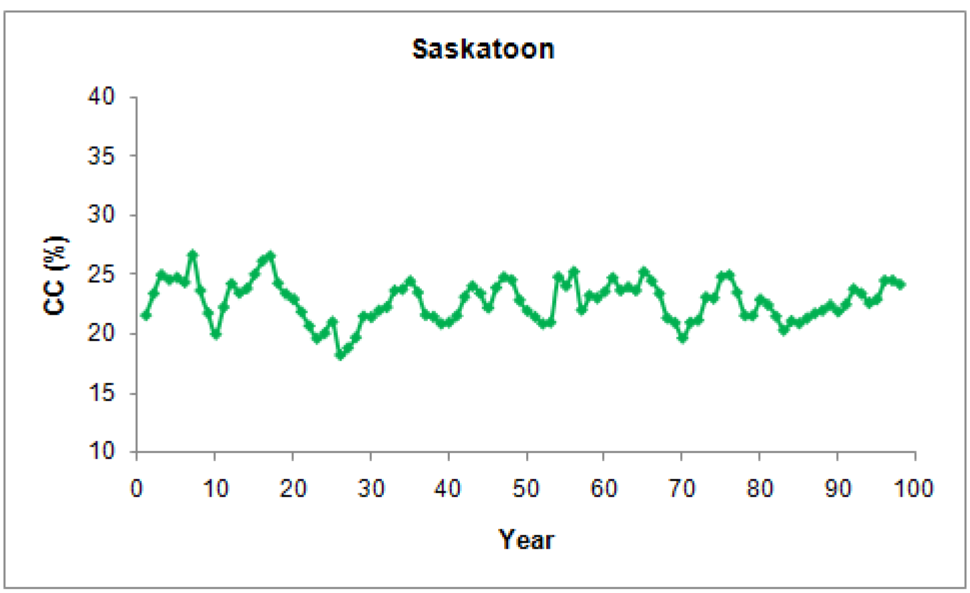

Figure 3.13: Capacity credit for the Saskatoon site.

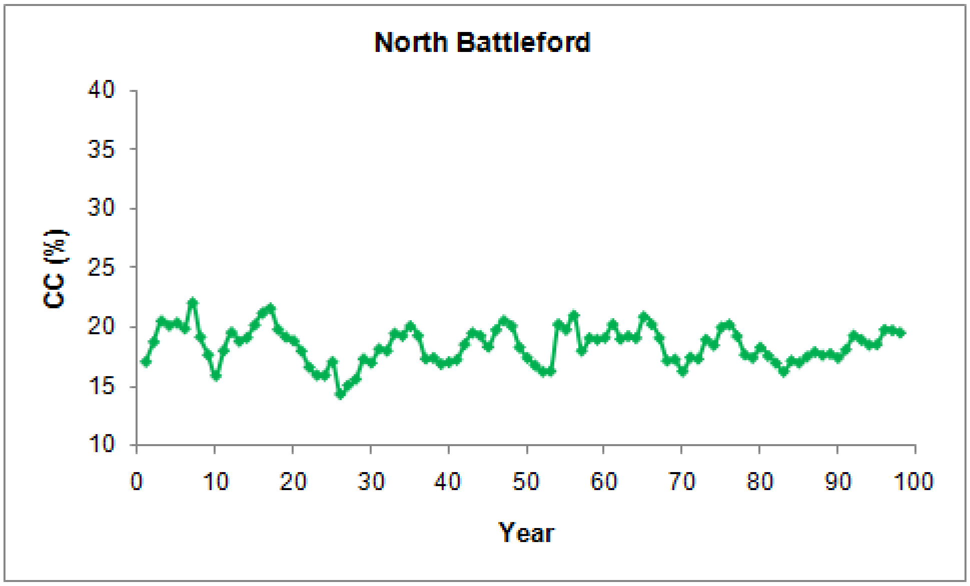

Figure 3.14: Capacity credit for the North Battleford site.

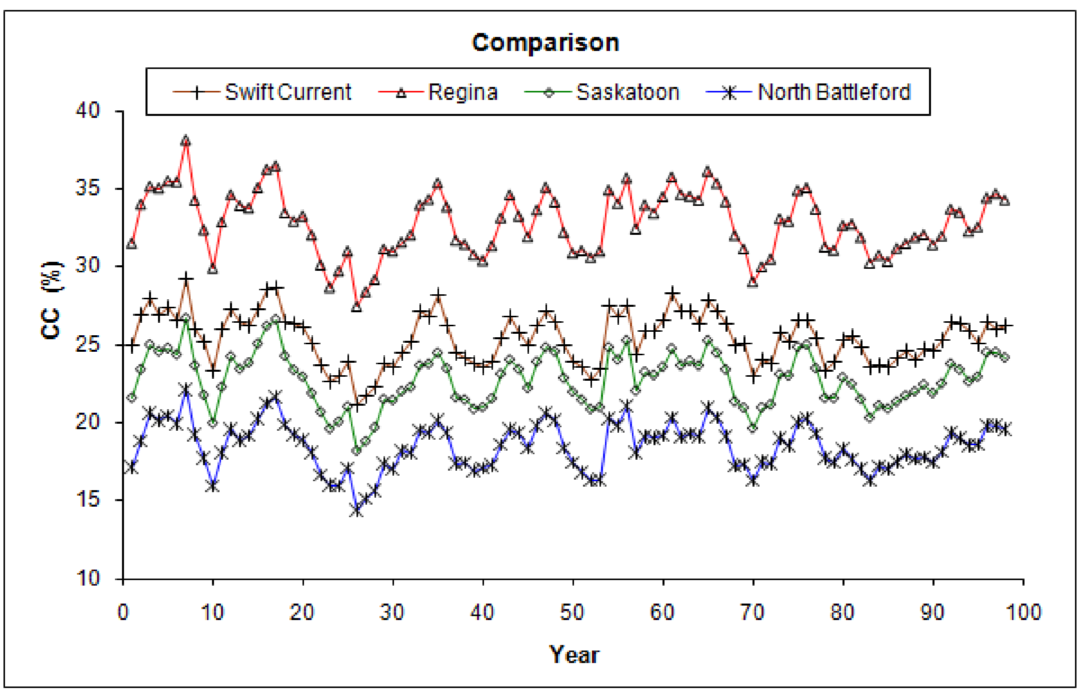

Figure 3.15: Capacity credit comparison for the four sites using the PJM method.

3.3.2 Parameter variation analysis for the four wind sites using a modified WTG

Tables 3.21, 3.22, 3.23 and 3.24 show the wind capacity credits for the four different sites using the modified WTG described in Section 3.2.2 and Figure 3.7 changed WTG rating. Figures 3.16, 3.17, 3.18 and 3.19 present wind capacity credit comparison graphs for the four different sites which show the effects of the modified WTG power curves at each site.

Figure 3.20 presents a comparison graph between four different sites i.e. Regina, Swift Current, Saskatoon and North Battleford with changed WTG rating for capacity credit evaluation.

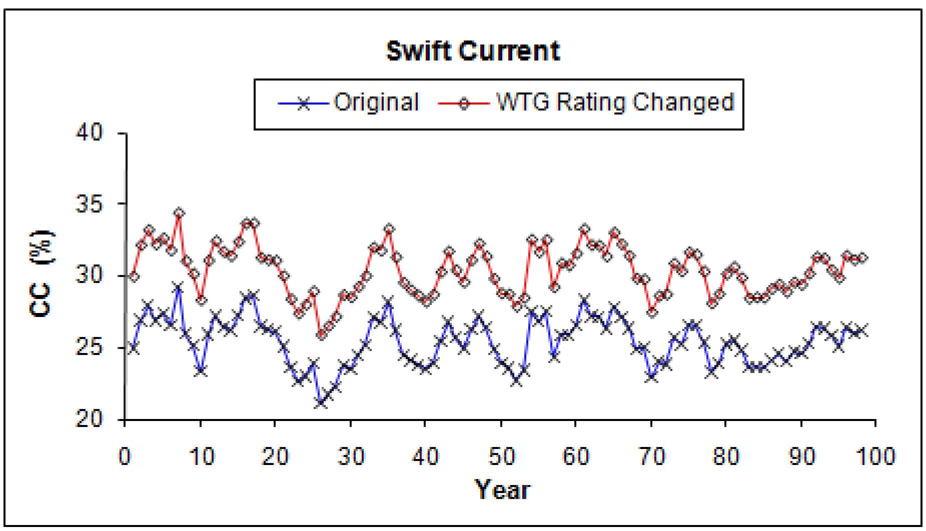

Figure 3.16: Capacity credit at the Swift Current site for the original and modified WTG using the PJM method.

Table 3.21: Wind capacity credit at the Swift Current site for a 98 year period and modified WTG using the PJM method.

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	29.963	34	31.750	67	31.382
2	32.140	35	33.271	68	29.824
3	33.200	36	31.292	69	29.764
4	32.196	37	29.534	70	27.449
5	32.628	38	29.012	71	28.604
6	31.765	39	28.623	72	28.715
7	34.395	40	28.191	73	30.847
8	31.023	41	28.695	74	30.330
9	30.143	42	30.274	75	31.633
10	28.307	43	31.694	76	31.463
11	31.054	44	30.389	77	30.305
12	32.435	45	29.567	78	28.078
13	31.674	46	31.079	79	28.742
14	31.376	47	32.237	80	30.142
15	32.369	48	31.339	81	30.601
16	33.662	49	29.807	82	29.869
17	33.672	50	28.781	83	28.429
18	31.258	51	28.720	84	28.501
19	31.097	52	27.858	85	28.472
20	31.044	53	28.462	86	29.091
21	30.008	54	32.522	87	29.406
22	28.374	55	31.643	88	28.887
23	27.367	56	32.505	89	29.554
24	27.992	57	29.217	90	29.386
25	28.930	58	30.864	91	30.174
26	25.866	59	30.734	92	31.299
27	26.494	60	31.549	93	31.203
28	27.153	61	33.273	94	30.392
29	28.674	62	32.139	95	29.859
30	28.503	63	32.104	96	31.393
31	29.256	64	31.341	97	31.100
32	30.009	65	33.019	98	31.258
33	31.973	66	32.195		

Table 3.22: Wind capacity credit at the Regina site for a 98 year period and modified WTG using the PJM method.

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	36.974	34	39.492	67	39.537
2	39.580	35	40.637	68	37.346
3	40.583	36	39.080	69	36.260
4	40.425	37	36.973	70	33.963
5	40.902	38	36.523	71	34.950
6	40.643	39	35.804	72	35.655
7	43.389	40	35.345	73	38.312
8	39.505	41	36.494	74	38.152
9	37.806	42	38.352	75	40.165
10	35.240	43	39.855	76	40.299
11	38.372	44	38.231	77	38.924
12	40.178	45	36.785	78	36.210
13	39.489	46	38.578	79	36.102
14	39.194	47	40.215	80	37.806
15	40.297	48	39.139	81	38.191
16	41.522	49	37.355	82	37.282
17	41.656	50	35.913	83	35.467
18	38.467	51	36.285	84	35.818
19	37.976	52	35.789	85	35.408
20	38.448	53	36.246	86	36.218
21	37.136	54	40.114	87	36.454
22	35.104	55	39.066	88	36.935
23	33.485	56	40.680	89	37.215
24	34.849	57	37.427	90	36.482
25	36.166	58	39.068	91	37.102
26	32.551	59	38.538	92	38.850
27	33.503	60	39.733	93	38.764
28	34.313	61	41.049	94	37.243
29	36.283	62	39.884	95	37.551
30	36.240	63	39.877	96	39.568
31	36.550	64	39.528	97	39.922
32	37.125	65	41.513	98	39.599
33	38.980	66	40.580		

Table 3.23: Wind capacity credit at the Saskatoon site for a 98 year period and modified WTG using the PJM method.

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	26.509	34	28.758	67	28.451
2	28.540	35	29.576	68	26.289
3	30.049	36	28.516	69	25.650
4	29.621	37	26.528	70	24.145
5	29.892	38	26.245	71	25.556
6	29.488	39	25.627	72	25.925
7	31.978	40	25.733	73	28.036
8	28.735	41	26.465	74	27.901
9	26.781	42	28.092	75	29.875
10	24.831	43	29.078	76	29.964
11	27.376	44	28.194	77	28.440
12	29.412	45	26.859	78	26.209
13	28.658	46	28.673	79	26.296
14	28.974	47	29.885	80	27.766
15	30.179	48	29.595	81	27.570
16	31.300	49	27.768	82	26.537
17	31.724	50	26.692	83	25.227
18	29.103	51	26.304	84	25.918
19	28.263	52	25.751	85	25.709
20	27.891	53	25.946	86	26.169
21	26.766	54	29.888	87	26.582
22	25.368	55	28.956	88	26.951
23	24.145	56	30.224	89	27.445
24	24.903	57	26.843	90	26.745
25	25.983	58	28.202	91	27.350
26	22.911	59	27.974	92	28.755
27	23.554	60	28.687	93	28.529
28	24.496	61	29.933	94	27.504
29	26.339	62	28.753	95	27.854
30	26.316	63	29.026	96	29.511
31	26.756	64	28.672	97	29.574
32	27.158	65	30.423	98	29.192
33	28.552	66	29.585		

Table 3.24: Wind capacity credit at the North Battleford site for a 98 year period and modified WTG using the PJM method.

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	21.244	34	23.675	67	23.468
2	23.171	35	24.559	68	21.381
3	24.889	36	23.645	69	21.224
4	24.574	37	21.573	70	20.025
5	24.836	38	21.544	71	21.335
6	24.377	39	21.000	72	21.426
7	26.728	40	21.145	73	23.247
8	23.619	41	21.544	74	22.688
9	22.024	42	22.842	75	24.369
10	20.076	43	23.907	76	24.584
11	22.422	44	23.377	77	23.592
12	24.084	45	22.380	78	21.720
13	23.302	46	23.913	79	21.543
14	23.541	47	24.934	80	22.579
15	24.581	48	24.349	81	22.012
16	25.663	49	22.426	82	21.264
17	26.066	50	21.399	83	20.375
18	24.101	51	20.908	84	21.284
19	23.436	52	20.488	85	21.102
20	23.231	53	20.552	86	21.637
21	22.229	54	24.651	87	22.082
22	20.684	55	23.996	88	21.921
23	19.800	56	25.319	89	22.034
24	19.974	57	22.187	90	21.584
25	21.223	58	23.430	91	22.282
26	18.216	59	23.221	92	23.621
27	19.070	60	23.525	93	23.295
28	19.643	61	24.695	94	22.652
29	21.478	62	23.365	95	22.758
30	21.154	63	23.584	96	24.161
31	22.228	64	23.420	97	24.221
32	22.216	65	25.386	98	23.970
33	23.797	66	24.697		

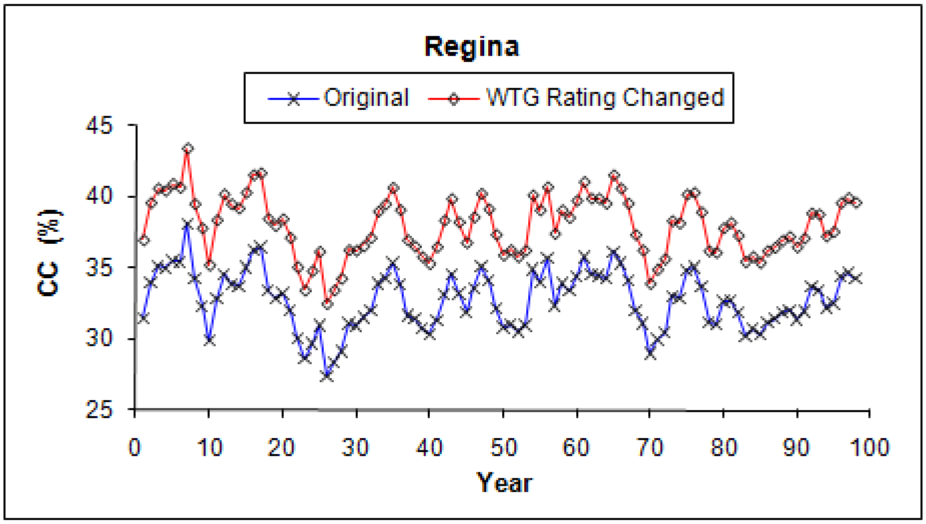

Figure 3.17: Capacity credit at the Regina site for the original and modified WTG using the PJM method.

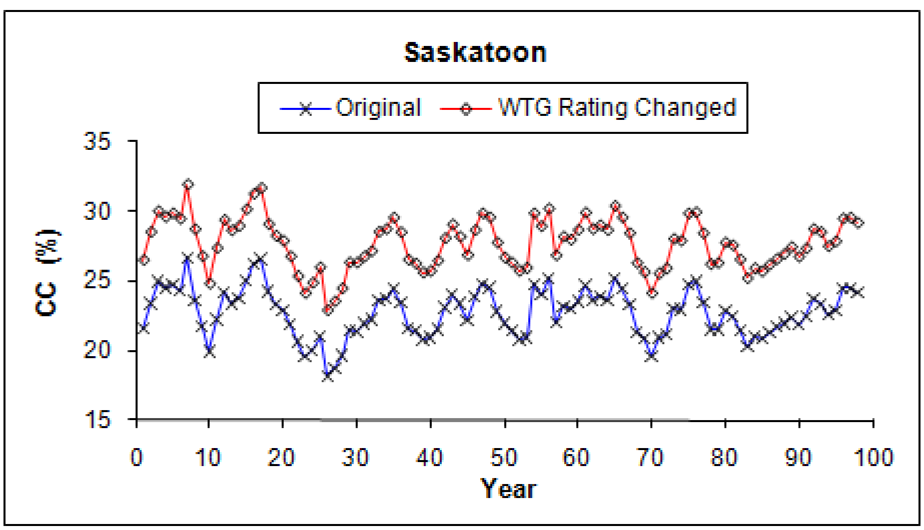

Figure 3.18: Capacity credit at the Saskatoon site for the original and modified WTG using the PJM method.

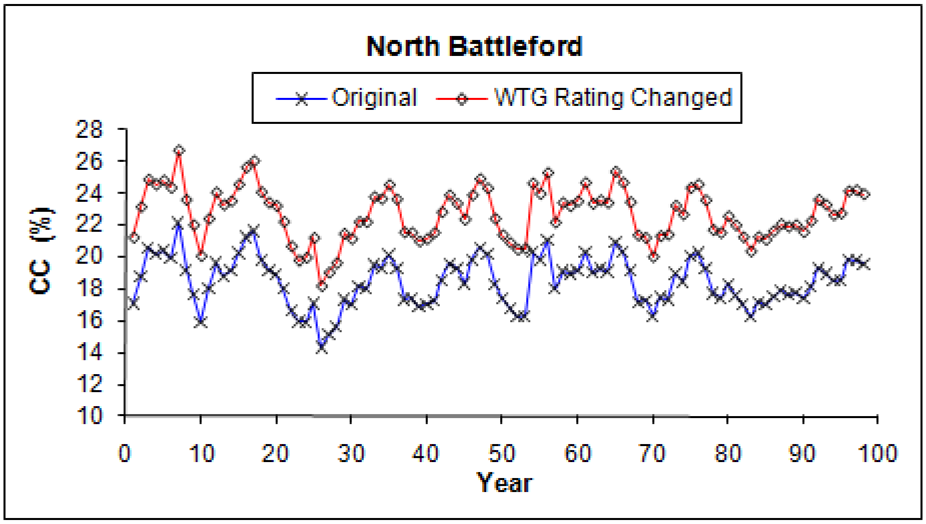

Figure 3.19: Capacity credit at the North Battleford site for the original and modified WTG using the PJM method.

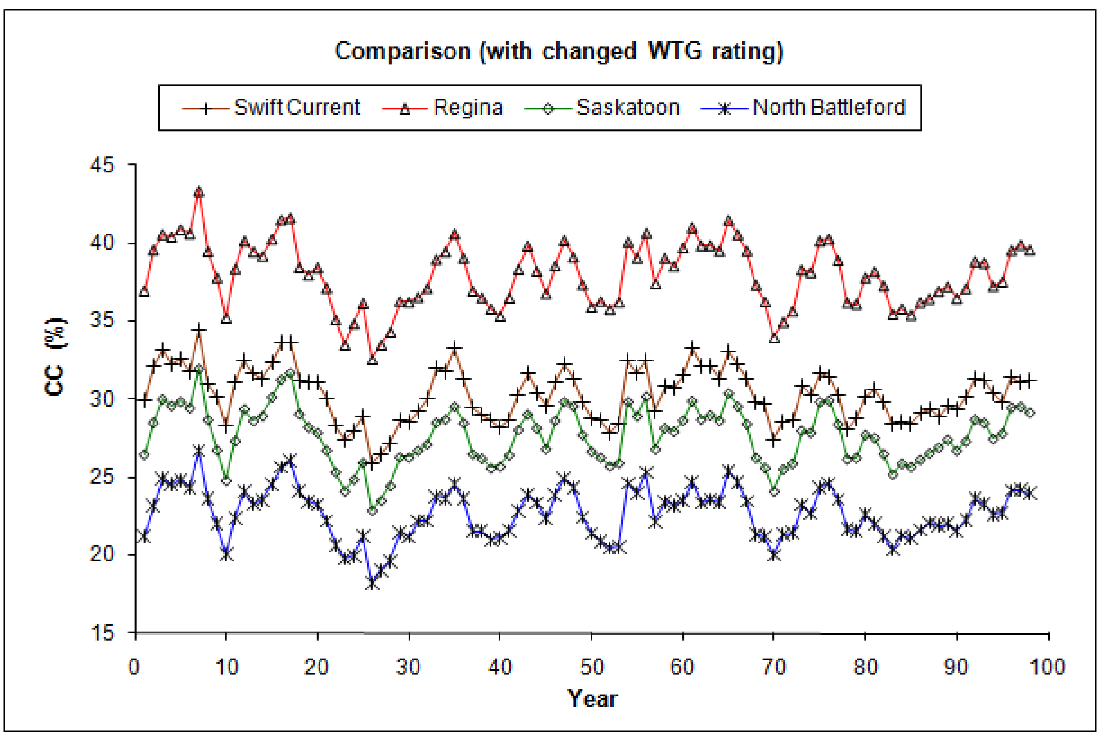

Figure 3.20: Capacity credit comparison for the four wind sites with the modified WTG using the PJM method.

3.4 Discussion-PJM Approach

The wind capacity credit associated with a 20 MW WECS for the Swift Current, Regina, Saskatoon and North Battleford sites was calculated for a 98 year period using the PJM approach. It is noticed that the wind capacity credit for the Regina site varies from a minimum value of 27.425% to a maximum value of 38.125%. The Swift Current site results vary from a minimum value of 21.095% to a maximum value of 29.258%, whereas Saskatoon site values vary from a minimum value of 18.176% to a maximum value 26.678% and at the North Battleford site they vary from a minimum value of 14.36% to a maximum value of 22.137%. Wind power performance obviously improves moving from North to South in the study area. The wind capacity credit was also calculated for the four different sites using the modified WTG rating over a 98 year period using the PJM approach. The results clearly show the higher capacity credit obtained for each site with the modified WTG rating. Lower cut-in-speeds will result in higher values of capacity credit and increase the capacity benefits of wind power.

3.5 Summary

Wind is an important source of energy. It has a capacity value but behaves far differently than conventional energy sources. Wind is highly variable, site specific and a renewable source of energy. It is relatively difficult to predict the behavior of the wind and therefore wind capacity credit evaluation is an interesting problem. The capacity credit associated with adding wind power to a conventional generating system is an important system planning parameter. There are various methods to calculate the wind capacity value. This chapter presents two analytical methods for capacity credit evaluation known as the SPP method and the PJM method .

It also illustrates the assigned capacity credit for both methods using parameter variation analysis i.e. for different wind sites, different WTG and changes in the percentile criterion used in the SPP method. It is noted that the wind capacity credit value fluctuates considerably from year to year and is highly dependent on the chosen year, month and site location. It is also noted that as the percentile criterion value decreases, the wind capacity credit value increases. Wind capacity credit values are also dependent on the WTG ratings. A lower cut-in value of WTG rating will give comparatively higher values of capacity credit. The results show that wind capacity credit values are higher for individual years compared to pooled years. Higher capacity credit values are also obtained using 3 year rolling averages compared to using 3 years of pooled data. The wind regime has a greater impact on capacity credit evaluation in the PJM method. In the study area, the wind regime obviously improves as the site moves from North to South and the capacity credit increases accordingly. The WTG design rating has an impact on the achieved wind capacity credit. The capacity credit values obtained using the SPP method for the different sites are considerably lower than those obtained using the PJM method. This is due to the utilization of the 85th percentile approach in SPP method. The PJM method approach appears to provide a more reasonable assessment of the potential capacity contribution of wind power.

Chapter 4

Capacity Credit Assessment using Probabilistic Analysis

4.1 Introduction

Power system reliability evaluation is an important process in system planning and design. The primary concern is to assess the required capacity of the generating facilities to satisfy the total system load demand. Different methods have been used by electric power utilities for generating capacity adequacy evaluation at the HL-I. Reliability techniques can be broadly divided into the two general categories of deterministic and probabilistic techniques. Deterministic techniques were the earliest techniques used to plan adequate generating capacity. At present, most large modern power utilities, use a probabilistic approach [3]. The fundamental approaches for adequacy evaluation using probabilistic techniques can be designated as being either analytical or simulation. Analytical approach is used in this research work to conduct generating capacity adequacy evaluation.

4.1.1 Deterministic methods

In this approach, system adequacy is evaluated on the basis of simple criteria termed as "rule of thumb methods" [1]. The following is a brief description of the most commonly used deterministic criteria.

Capacity reserve margin (CRM)

The capacity reserve margin is expressed as a fixed percentage of the total installed capacity. The system reliability is unacceptable when the capacity reserve is less than the specified value.

Loss of the largest unit

The required capacity reserve in a system should be at least equal to the capacity of the largest unit. This method prevents load curtailment due to an outage of any single generating unit. Addition of larger units to the system increases the system reserve.

Loss of the largest unit and a percent margin

The capacity reserve is equal to or greater than the capacity of the largest unit plus a fixed percentage of either the peak load or the total installed capacity.

$$CR \geq CLU + X \times PL$$

$$CR \geq CLU + X \times IC$$

where CR = Capacity reserve

CLU = Capacity of the largest unit

PL = Peak load

IC = Installed capacity, and

X = Multiplication factor, usually between 5% - 15%.

The main disadvantage of deterministic techniques are that they estimate the system adequacy largely on the basis of past experience and judgment and do not recognize and reflect the random nature of system component failures and the uncertainty in load variation. Therefore the actual system risk cannot be determined by the deterministic methods.

4.1.2 Probabilistic methods

Probabilistic methods were developed to overcome the limitations of deterministic methods and to provide quantitative measures of system reliability. Many utilities around the world use probabilistic methods in generating capacity adequacy assessment. Probabilistic methods can be broadly divided into the two different categories of analytical and simulation methods.

Simulation methods

Simulation methods are more sophisticated procedures that treat the problem as a series of experiments and hence large amounts of computing time are required. In this technique the reliability indices are obtained by simulating the actual process and random behavior of the system.

Analytical methods

In an analytical method the system is represented by a mathematical model and system risk indices are evaluated from these models using mathematical solutions. Most of the existing techniques are based on analytical methods. Analytical methods are relatively simple to apply and their results can be readily reproduced.

The basic approach for generating capacity adequacy evaluation consists of three parts designated as the generation model, load model and the risk model. The generation model used in most analytical methods is normally in the form of an array of capacity levels and their associated probabilities of existence and is known as a capacity outage probability table (COPT). The COPT can be obtained by using a well known recursive technique [1]. Each generating unit in the system is represented by either a two-state or a multi-state model.

Generating unit model

The two-state model for a generating unit is shown in Figure 4.1. The generating unit is considered to be either fully available (Up) or totally out of service (Down). In the figure, λ is the failure rate and μ is the repair rate.

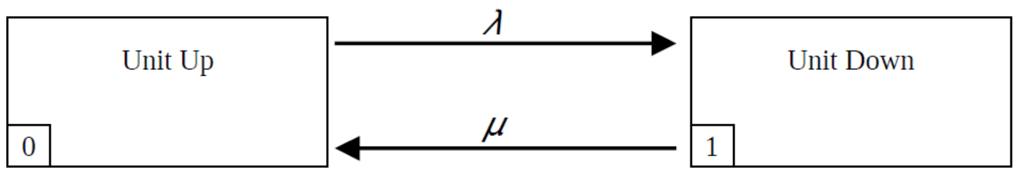

Figure 4.1: Two-state model for a generating unit.

The generating unit Forced Outage Rate (FOR), also known as the unavailability is a basic parameter used in generating capacity adequacy evaluation. The availability (A) and the unavailability (U) are given by (4.1) and (4.2) respectively.

$$A = \frac{\mu}{\lambda + \mu} = \frac{m}{r + m} = \frac{\sum[UpTime]}{\sum[DownTime] + \sum[UpTime]} \tag{4.1}$$

$$U = \frac{\lambda}{\lambda + \mu} = \frac{r}{r + m} = \frac{\sum[DownTime]}{\sum[DownTime] + \sum[UpTime]} \tag{4.2}$$

where m = mean time to failure = MTTF = $\frac{1}{\mu}$

r = mean time to repair = MTTR = $\frac{1}{\lambda}$

The COPT for a two-state generating unit can be created using a recursive algorithm [1]. The cumulative probability of a certain capacity outage state of X MW calculated after addition of a unit capacity of C MW with a forced outage rate U, is given by (4.3)

$$P(X) = (1 - U)\acute{P}(X) + U\acute{P}(X - C) \tag{4.3}$$

where $\acute{P}(X)$ and $P(X)$ are the cumulative probability of the capacity outage state of X MW before and after the unit of capacity C is added respectively. The above equation is initialized by setting $\acute{P}(X) = 1.0$ for $X < 0$, and $\acute{P}(X) = 0$, otherwise.

A multi-state generating unit is a unit having one or more derated or partial output states in addition to the fully up and fully down states [1]. The model for a generating unit with one derated or partial output state is shown in Figure 4.2.

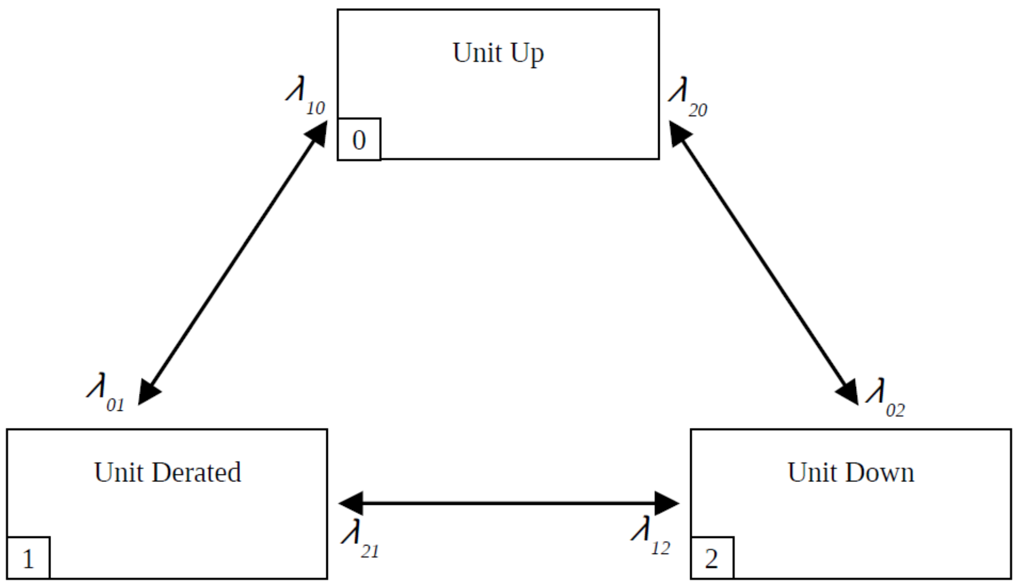

Figure 4.2: Three-state model for a generating unit. λ_{ij} is the transition rate between state i and state j.

Equation (4.3) is modified as shown below for a generating unit with derated states.

$$P(X) = \sum_{i=1}^{n} P_i \times \acute{P}(X - C_i) \tag{4.4}$$

where n = number of unit states

P_i = Probability of existence of the unit state

C_i = Capacity outage state i for the unit being added.

After the addition of all the generating units, the COPT table is complete. The generation model obtained from the COPT and an appropriate load model are combined to evaluate the desired risk indices. At the present time, the analytical approaches fall into one of the following general categories:

Loss of load method

The generation model and the load model are combined to produce the system risk indices as shown in Figure 4.3.

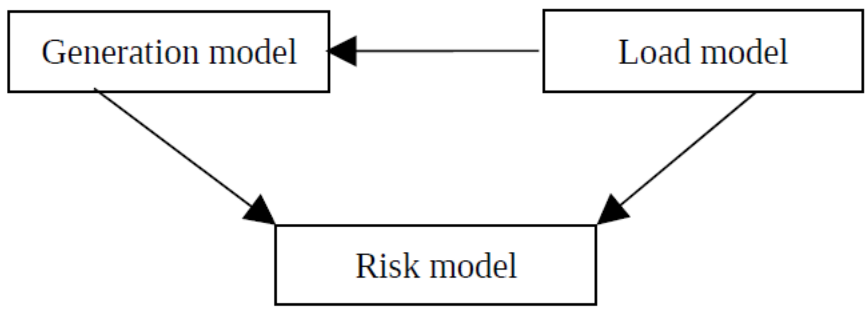

Figure 4.3: Basic concept in HL I Evaluation [1].

The risk indices obtained are overall system adequacy indices which do not include transmission constraints and reliabilities. In an analytical approach, the basic generation model is normally represented in the form of an array of capacity levels and their associated probabilities of existence, known as a capacity outage probability table (COPT).The load profile is normally represented by either the daily peak load variation curve (DPLVC) or the load duration curve (LDC). The risk model obtained by combining the COPT with the DPLVC, gives the expected number of days in a year in which the system generating capacity will be insufficient to satisfy the system daily peak load. This is designated as the loss of load expectation (LOLE). The risk model obtained by combining the COPT with the LDC gives the expected number of hours in the year that the hourly load will exceed the available generating capacity. Figure 4.4 shows that when an outage X_k, associated with probability p_k, exceeds the reserve, a loss of load situation arises for a time t_k. Each outage state associated with probability p_k is superimposed on the load model and the time t_k for each load loss event is calculated.

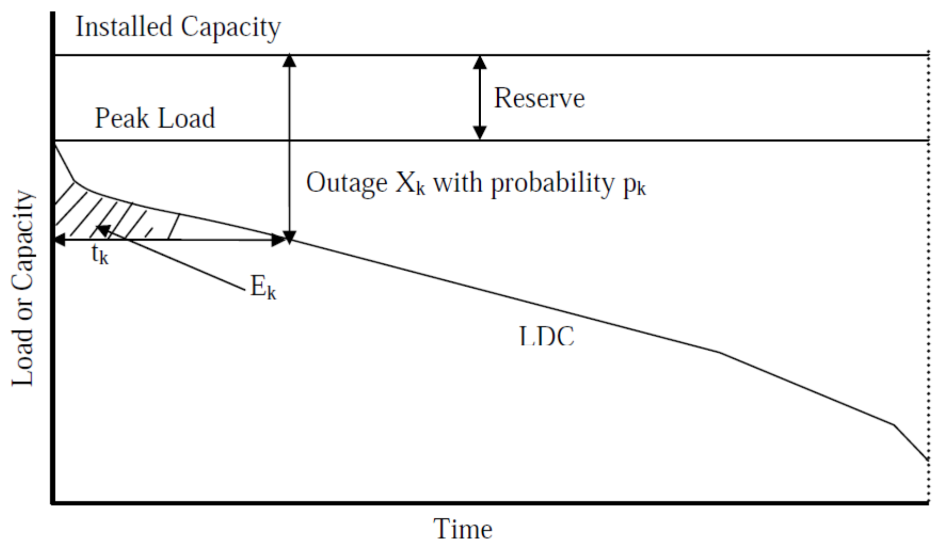

Figure 4.4: Evaluation of Risk Indices.

The total LOLE for a specified period of time can be obtained by the following equation.

$$\text{LOLE} = \sum_{k=1}^{n} p_k t_k \tag{4.5}$$

where n = number of capacity outage states in the COPT,

p_k = individual probability of capacity outage X_k, and

t_k = load loss occurrence time due to outage X_k.

The LOLE is in days per year or hours per year depending on the load profile i.e. whether the daily peak load or the load duration curve is used respectively.

Loss of energy method

The area under the load duration curve indicates the energy utilized during the specified period and can be used to evaluate an expected energy not supplied index due to insufficient installed capacity. When an outage X_k with probability p_k exceeds the reserve it results in an energy curtailment E_k. Each outage state X_k associated with probability p_k is superimposed on the load duration curve and the energy curtailment E_k for each load loss event is calculated. The total expected energy curtailment or LOEE can be obtained using the following equation

$$\text{LOEE} = \sum_{k=1}^{n} E_k p_k \tag{4.6}$$

The reliability indices units per million (UPM), system minutes (SM) and the energy index of reliability (EIR) are shown in (4.7), (4.8) and (4.9) respectively. The total energy requirement in a specified period is E.

$$\text{UPM} = \frac{\text{LOEE}}{E} \times 10^6 \tag{4.7}$$

$$\text{SM} = \frac{\text{LOEE}}{PL} \times 60 \tag{4.8}$$

$$\text{EIR} = 1 - \sum_{k=1}^{n} \frac{P_k \times E_k}{E} \tag{4.9}$$

Frequency and duration method

The frequency and duration method is a complicated approach compared with the loss of load and loss of energy approaches. In this method, Markov models are used to represent the generating units and the system load. Additional data such as the generating unit and load state transition rates are required in the frequency and duration method. The indices obtained from this approach are expressed in terms of the expected frequency, average duration and probability of encountering various negative margin states [1]. This approach is not widely used in electric utilities in generation adequacy evaluation. The basic concepts are presented in [2].

Load modification method

A single COPT generation model is used in the loss of load and loss of energy method. In the load modification method, the generation models used are the capacity outage probability tables for each individual generating unit in the system instead of a single COPT. The LDC is the load model used in this approach. This method is based on the concept of determining the equivalent load model that appears to the rest of the system when each unit is placed sequentially in service. The load modification method is a sequential process to modify a given load model to produce an final equivalent load model. The basic concepts and application of this method are presented in [31].

4.2 System reliability indices

The LOLE and LOEE reliability indices used in this research were obtained using an analytical program developed by D. Huang in her M.Sc. research [32]. The RBTS is used as the study system in this research. Table 4.1 and Figure 4.5 present the LOLE indices for a range of peak load levels for the RBTS. The LOLE value increases with increase in peak load. The suggested peak load for the RBTS is 185 MW [33]. The LOLE at this level is 1.09 hrs/yr. The LOEE is also a basic reliability index used in generating system adequacy evaluation. Table 4.2 and Figure 4.6 present the LOEE indices at various peak load levels for the RBTS. The LOEE at the suggested peak load of 185 MW for the RBTS is 9.86 MWh/yr.

Table 4.1: The LOLE at various peak loads for the RBTS

Peak load (MW)	LOLE (hrs/yr)
200	3.6305
190	1.7107
185	1.0919
180	0.6822
170	0.2548
160	0.0926
150	0.0367

Table 4.2: The LOEE at various peak loads for the RBTS

Peak load (MW)	LOEE (MWh/yr)
200	37.9318
190	15.7875
185	9.8608
180	6.0116
170	2.1869
160	0.8098
150	0.2925

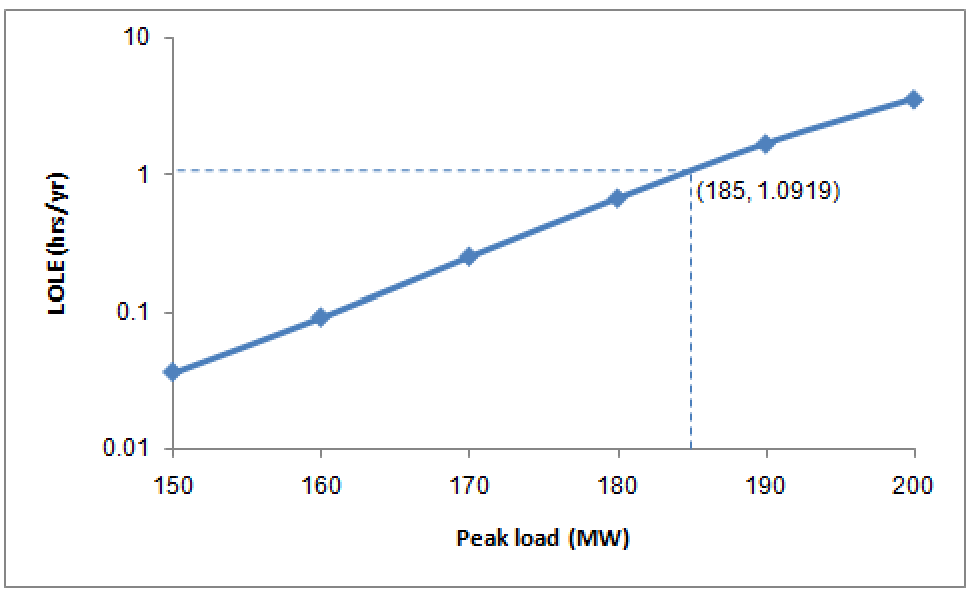

Figure 4.5: The LOLE as a function of the peak load for the RBTS.

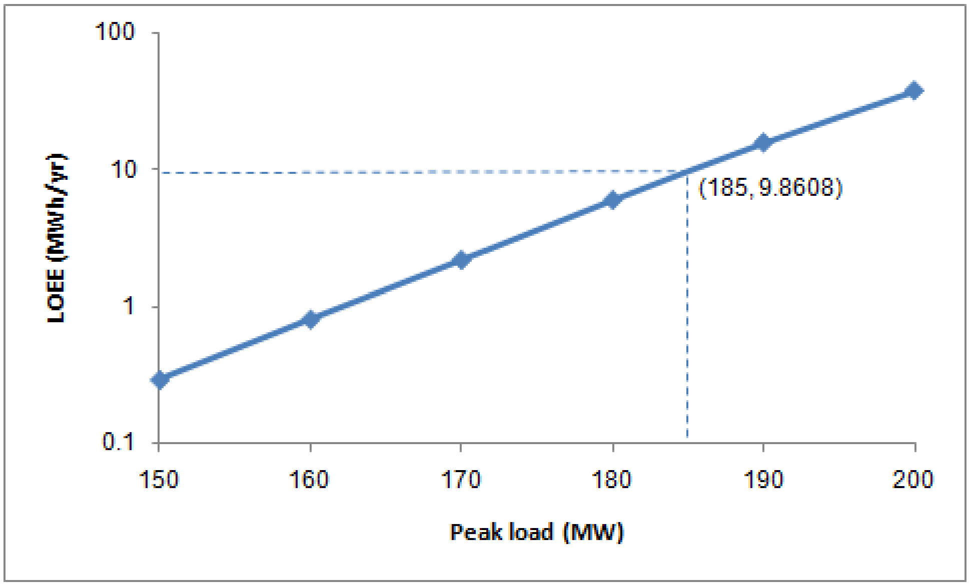

Figure 4.6: The LOEE as a function of the peak load for the RBTS.

4.3 Effective load carrying capability method (ELCC)

The effective load carrying capability method (ELCC) is a well established technique for calculating the capacity credit associated with a generating unit. The ELCC is a probabilistic method that can be used to analyze the capacity benefit associated with WECS. The most commonly used reliability measure to determine the capacity credit of a wind plant in the ELCC approach is the LOLE. The ELCC capacity measurement is normally done at the criterion reliability level. The peak load is increased gradually until the level of system reliability associated with the addition of wind capacity is the same as that of the original system without considering wind capacity. The addition of a WECS to the system reduces the LOLE at a given peak load. Two LOLE curves, without and with WECS are plotted as a function of peak load. The ELCC is the horizontal distance between the two reliability profiles at a particular LOLE level [34]. The wind speed varies significantly from year to year in addition to hour to hour and therefore, sufficient wind speed data are required to create a wind power model and calculate the ELCC.

4.3.1 Estimation of wind capacity credit using the ELCC method

The eleven-state wind power model for the Swift Current site given in Table 2.6 is presented in Table 4.3 and Figure 4.7. This eleven-state model for a 20 MW WECS was added to the RBTS to determine the HL-1 adequacy indices as a function of the peak load. In this section, both the LOLE and LOEE are used for capacity credit evaluation. Table 4.4 and Figure 4.8 show the RBTS LOLE at different peak loads with and without the 20 MW WECS addition. The LOLE without the WECS is 1.09 hrs/yr. The maximum allowable peak load at a risk level of 1.09 hrs/yr in the RBTS with the 20 MW WECS addition is 189.58 MW. The increase in peak load carrying capability of 4.58 MW (189.58-185) is the capacity credit of the wind power addition i.e. 22.9165 in percent. The benefit associated with the addition of a 20 MW WECS to the RBTS generally increases as the peak load increases. Table 4.5 and Figure 4.9 show the behavior of the reliability index LOEE at various peak loads with and without wind for the RBTS. With wind addition, risk indices such as the LOLE and LOEE values decrease. Table 4.6 shows the capacity credit values at different peak loads for the RBTS. The results show that within a 15 MW variation in peak load for the RBTS, the variations in capacity credit are relatively small.

Table 4.3: Eleven-state wind power model for the Swift Current site

Wind power (%)	Probability
0	0.302483
10	0.182428
20	0.126015
30	0.092306
40	0.068458
50	0.051924
60	0.039312
70	0.030124
80	0.023168
90	0.017839
100	0.065944

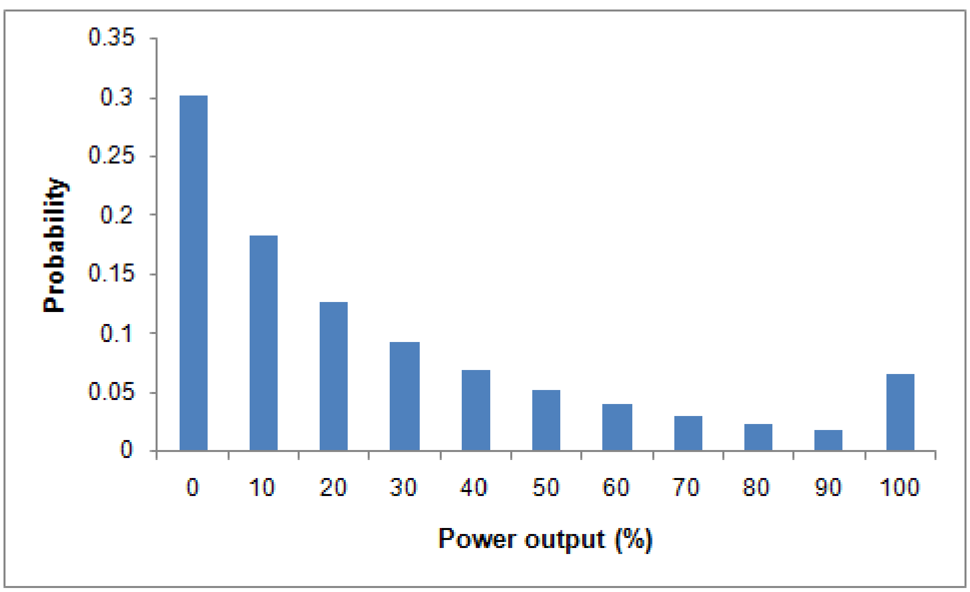

Figure 4.7: Power probability distribution for the eleven-state WECS model.

Table 4.4: LOLE with and without wind at different peak loads for the RBTS

Peak load(MW)	LOLE (hrs/yr) with wind	LOLE (hrs/yr) without wind
200	2.5265	3.6305
190	1.1342	1.7073
185	0.7175	1.0918
180	0.4442	0.6821
170	0.1624	0.2547
160	0.0603	0.0926
150	0.0233	0.0367

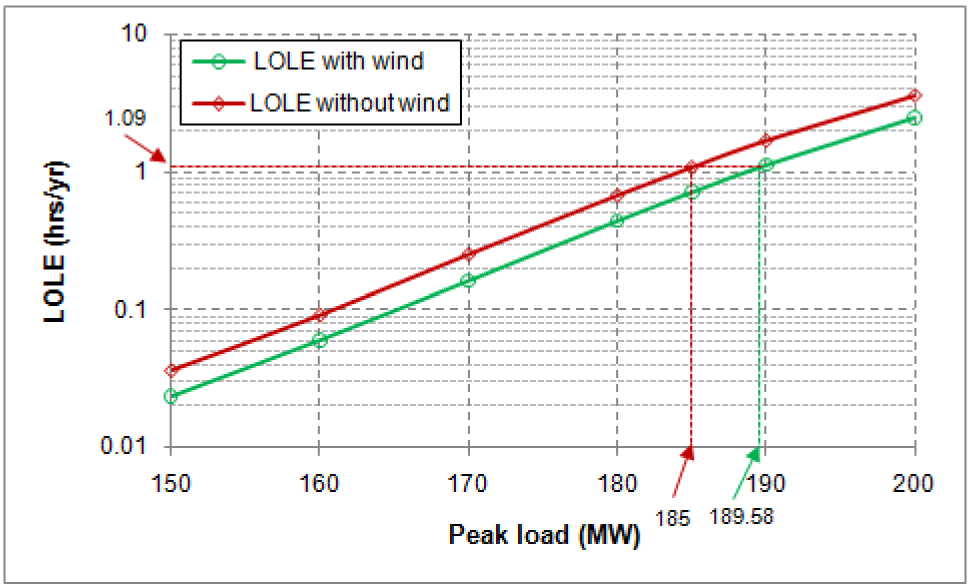

Figure 4.8: LOLE with and without wind as a function of peak load (RBTS).

Effect of wind power penetration level and WTG rating

There are rapid growths in wind penetration in power systems around the world. The wind penetration level is the ratio of the installed wind capacity to the total generating capacity. It can be calculated using (4.10). This section analyzes the effect of wind penetration on the capacity credit of wind power.

$$\text{Wind power penetration level} = \frac{\text{Installed wind capacity}}{\text{Total installed capacity}} \tag{4.10}$$

Table 4.5: LOEE with and without wind at different peak loads for the RBTS

Peak load(MW)	LOEE (MWh/yr) with wind	LOEE (MWh/yr) without wind
200	25.4807	37.9324
190	10.3291	15.7880
185	6.3841	9.8613
180	3.8793	6.0120
170	1.4081	2.1872
160	0.5188	0.8101
150	0.1814	0.2928

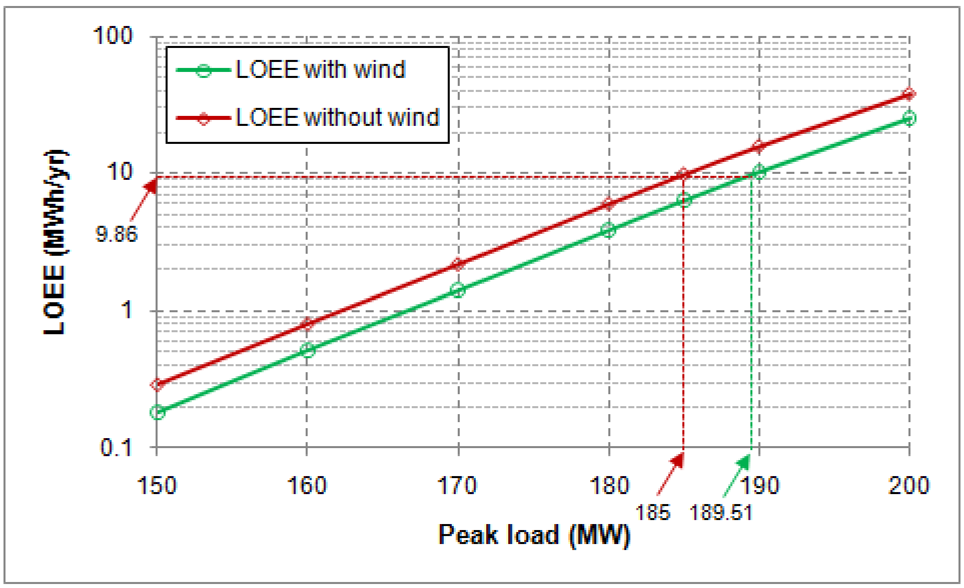

Figure 4.9: LOEE with and without wind as a function of peak load (RBTS).

Table 4.6: Capacity credit (CC) at different peak loads for the RBTS

Peak load (MW)	CC considering LOLE (hrs/yr)	CC considering LOEE (MWh/yr)
170	4.1935	4.3103
185	4.5833	4.5148
200	4.5280	4.7243

Wind capacity from 20 MW to 100 MW in 20 MW increments were added to the RBTS to study the effect of penetration level on the wind capacity credit. Table 4.7 shows that wind penetration has a significant impact on the wind power capacity credit and the capacity credit decreases with increase in the wind penetration. The modified WTG rating used in Chapter 3 for the SPP and PJM methods (described in Sections 3.2.2 and 3.3.2) was used to analyze the impact of WTG rating on the wind power capacity credit. The eleven-state model with the changed WTG rating (designated as WTG-B) for the Swift Current site is shown in Table 4.8. Table 4.9 shows the LOLE index with and without wind at different peak loads for the RBTS with the WTG-B rating. It can be seen that slightly lower LOLE values are obtained in the WTG-B case than those obtained with the original rating. Table 4.10 presents the capacity credit and penetration level of 100 MW of wind power with WTG-B. The capacity credit increases due to the modified WTG rating.

Table 4.7: Capacity credit and wind power penetration level with the addition of different wind capacities to the RBTS

Wind capacity (MW)	Capacity credit (MW)	Capacity credit (%)	Penetration level%
20	4.583	22.92	7.69
40	7.169	17.92	14.29
60	8.775	14.63	20.00
80	10.329	12.91	25.00
100	11.222	11.22	29.41

Table 4.8: Eleven-state wind model for the Swift Current site with WTG-B

Wind power (%)	Probability
0	0.155051
10	0.245507
20	0.141993
30	0.10267
40	0.077305
50	0.05884
60	0.045439
70	0.035372
80	0.02768
90	0.021829
100	0.088313

Table 4.9: LOLE with and without wind at different peak loads for the RBTS with WTG-B

Peak load(MW)	LOLE (hrs/yr) with wind	LOLE (hrs/yr) without wind
200	2.3052	3.6305
190	1.0199	1.7073
185	0.6437	1.0918
180	0.3970	0.6821
170	0.1442	0.2547
160	0.0538	0.0926
150	0.0207	0.0367

Table 4.10: Capacity credit and wind power penetration level with the addition of different wind capacities to the RBTS system with WTG-B

Wind capacity (MW)	Capacity credit (MW)	Capacity credit (%)	Penetration level (%)
20	5.955	29.78	7.69
40	9.436	23.59	14.29
60	12.242	20.40	20.00
80	14.313	17.89	25.00
100	15.945	15.94	29.41

4.4 Discussion

The three studied techniques for wind capacity credit evaluation designated as the SPP, PJM and ELCC methods are quite different from each other. The same basic input data are used in the first two methods but the procedure and execution are quite different in each case. The SPP and PJM methods are both based on a time period basis. The SPP method is applied on a monthly basis i.e., capacity credit is calculated for each individual month. The 85th percent parameter is a major factor in this method. The capacity value of the 85th percentile is taken as the wind capacity credit for that particular month. Comparatively low capacity credit values are obtained due to this selection. The 85th percentile parameter appears to be based on the SPP group members subjective opinion. Decreasing the 85th percentile criterion will result in comparatively higher wind capacity credit values similar to those obtained in other discussed methods. In the PJM method, the June, July and August data values are considered together and the capacity credit is calculated during the hours of 3 PM to 7 PM. The PJM approach is better than the SPP method. The ELCC method is a well established probabilistic approach and is totally different than the SPP and PJM methods for capacity credit evaluation. The ELCC capacity measurement is normally done at the criterion reliability level. This method considers all months and all the hourly data values.

4.5 Summary

This chapter presents a brief discussion on generating system adequacy evaluation. Important system reliability indices such as LOLE and LOEE are also discussed. The LOLE and LOEE values increase with increase in peak load. The system reliability improves with the addition of WECS to the RBTS.

A WECS addition reduces the LOLE and LOEE values at a given peak load. The ELCC method indicates that within a 15 MW variation in peak load for the RBTS, the variation in capacity credit is relatively small. The effects of wind penetration and WTG rating on the capacity credit of wind power were studied. Wind penetration has a significant impact on the wind power capacity credit expressed in percent and this capacity credit decreases with increase in the wind penetration. The capacity credit increases slightly due to the modified WTG rating as slightly lower LOLE values are obtained with the modified WTG rating than those obtained with the original WTG rating.

Chapter 5

Summary and Conclusion

Wind power is the most mature and capable source of renewable energy and is considered to be an encouraging and promising alternative for power generation because of its tremendous environmental, social and economic benefits together with public and government support. As a result, wind power applications are being given very serious consideration throughout the world to reduce environmental degradation. Many governments already have energy plans and policies which include significant percentage increases in global power generation from wind energy in the near future. The growing application of wind power dictates the need to develop methods to evaluate the system reliability and the capacity value of wind power. Wind is generally seen as a source of energy, but it also has some capacity value. In order to evaluate the actual benefits of adding wind power to a conventional generating system this capacity credit value needs to be known. It is therfore important to examine the different power system reliability methodologies used to assess the capacity credit of wind power.

Chapter 1 presents the basic concepts related to power system reliability evaluation. It also introduces power systems utilizing wind energy and the growth of wind energy applications throughout the world. Chapter 2 presents a brief discussion on wind system modeling and evaluation techniques. The modeling procedure is broadly divided into the three zones of wind speed modeling, wind power modeling and system risk modeling. Significant amounts of historical data are required for the development of a comprehensive wind speed model for a particular geographic site. Historical wind speed data for four different sites in Canada (Swift Current, Regina, Saskatoon and North Battleford) having different geographic locations were used in this research work. An auto-regressive and moving average model (ARMA) has been used to simulate the fluctuating wind speeds. Wind power modeling is conducted by applying the relationship between the wind speed and the output power of a WTG. The power output of a WTG is dependent on the wind regime and will increase if the facilities are located at a site having higher wind velocities. Risk modeling is obtained by combining the power system model including the wind energy (PSIWE) generation with the load model. An apportioning method is illustrated and utilized to establish selected multi-state WECS models. In this research work, the assumption is used that a WECS consists of multiple identical WTG units with zero FOR. In this case the WECS multistate model is the same as that of a single WTG unit.

It is hard to predict the behavior of the wind as it is site specific and highly variable. Therefore, capacity credit evaluation of wind energy is rather an interesting subject to study. As noted earlier, wind is generally considered to be a source of energy but not a source of capacity. It is however, equally important to consider the issue of WECS capacity credit as WECS penetrations increase in electric power systems. Capacity credit is a measure of the load carrying contribution that wind power can make to an electric power system. Chapter 3 introduces two different methods known as the Southwest Power Pool method and the Pennsylvania-New Jersey-Maryland method for evaluating wind power capacity credit. The SPP and PJM methods are both applied on a time period basis.It also presents the capacity credit for both methods using parameter variation analysis i.e. for different wind sites, different WTG and changes in the percentile criterion used in the SPP method.

In the SPP method, it is observed that the wind capacity credit value highly fluctuates from year to year i.e. each year's value of capacity credit is far different from the next year's value. Wind capacity credit is also highly dependent on the chosen year, month and site location . A particular site may be better for a particular month and year. It is also noted that as the selected criterion value decreases, the wind capacity credit value increases. The wind power capacity credit value is also dependent on the WTG rating. A lower wind turbine cut-in value rating provides a comparatively higher value of capacity credit. It is also observed that wind capacity credit is higher in certain individual years than in pooled years. Higher capacity credit values are obtained using 3 year rolling averages in comparison with 3 years of pooled data, as a rolling average reduces the volatility of the annual values. The wind regime has a greater impact on the capacity credit evaluation in the PJM method. In the Saskatchewan study area, the wind regimes obviously improve as the site moves from North to South and the capacity credit increases accordingly. The WTG rating has an impact on the wind power capacity. Lower WTG cut-in values will result in higher values of capacity credit and increase the capacity benefits of wind power. Comparatively lower values of capacity credit are obtained in the SPP method due to applying the 85th percentile criterion value. The PJM method provides more reasonable capacity credit evaluation of wind power than the SPP approach.

Chapter 4 presents some basic reliability concepts in generating capacity adequacy evaluation. The applied technique utilizes generation and load models to create a risk model contianing the reliability indices. It is an important process in power system reliability evaluation and is extremely useful for power system planning, design and operation. A number of various evaluation techniques are available for power system reliability studies. These techniques can be categorized as being either deterministic or probabilistic methods. Both deterministic and probabilistic methods are used by power utilities in various aspects of power system planning. Both techniques are discussed in this chapter. Deterministic techniques cannot recognize the actual risk in a system and power utilities are slowly changing from deterministic to probabilistic criteria. Probabilistic approaches can be broadly divided into the two categories of analytical and Monte Carlo simulation techniques. In analytical techniques, the generation model is represented by a capacity outage probability table, which contains the capacity and probability of each outage level in the generating system. The load model is represented by either a daily peak load variation curve or an hourly load variation curve. Both analytical and simulation techniques have their own advantages and disadvantages and each can be used for a particular application. Analytical methods are relatively simple to apply and the results can be easily reproduced. Generally, simulation techniques are used when direct analytical techniques are unsuitable. The research conducted in this thesis applies analytical methods for wind power capacity credit evaluation. The reliability test system known as the RBTS is used in this research. The RBTS is a basic reliability test system that evolved from the educational and research programs conducted at the University of Saskatchewan. The primary concern is to assess the required capacity of the generating facilities to meet the total system load demand using relevant system reliability indices such as the LOLE and LOEE. The impact of basic system parameters on system reliability was initiated by considering the conventional system. The system reliability improves with the addition of a WECS to the RBTS and the WECS addition reduces the LOLE and LOEE values at a given peak load. The most common approach to assess the capacity credit of wind power is the effective load carrying capability (ELCC) and is described in this chapter. The ELCC analysis was conducted using the LOLE and LOEE criterion reliability indices. The studies show that within a 15 MW variation in peak load, the variations in capacity credit for the RBTS are relatively small. Results from the studies conducted to evaluate the effect of wind penetration and different WTG ratings on the wind capacity credit are presented in this thesis and show that the capacity credit is greatly influenced by the wind penetration level. The addition of more wind capacity to the RBTS results in lower capacity credit values. The WTG rating also has an impact on the wind power capacity credit value. Slightly lower LOLE values were obtained using the modified WTG rating compared with those obtained using the original rating. The capacity credit increased slightly due to the modified WTG rating.

The three studied techniques for wind capacity credit evaluation designated as the SPP, PJM and ELCC methods are quite different from each other. The same basic input data are used in the first two methods but the procedure and execution are different in each case. The ELCC method considers all months and all the hourly data values. The capacity credit for the Swift Current site was 22.92% using this method (Table 4.7). In the PJM method, the June, July and August data values are considered together and the capacity credit is calculated during the hours of 3 PM to 7 PM. In this method, the capacity credit for the Swift Current site vary from a minimum value of 21.095% to a maximum value of 29.258% using 100 years of data (Table 3.17) and varies from a minimum value of 24.957% to 27.972% using five years of data. The SPP method is applied on a monthly basis i.e. the capacity credit is calculated for each individual month. The 85th percent parameter is a major factor in this method. The capacity credit for the Swift current site considering the months of June, July and August vary from a minimum value of zero to a maximum value of 5.687% (Table 3.3). Decreasing the 85th percentile criterion results in comparatively higher wind capacity credit values similar to those obtained in the other discussed methods. The PJM method approach appears to provide a more reasonable assessment of the potential capacity contribution of wind power than the SPP technique.

In conclusion, it is suggested that the models, methods and results presented in this thesis should prove to be valuable to system planners assessing generating capacity adequacy evaluation incorporating wind energy.

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Appendix A

Load Model

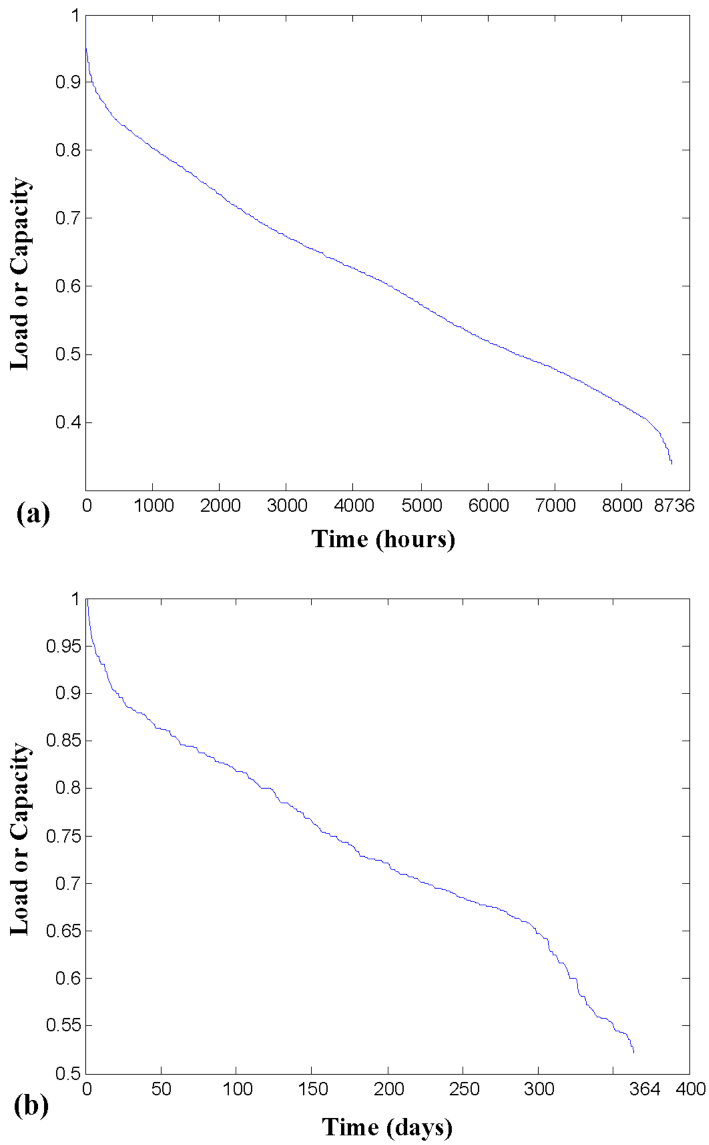

Figure A.1: (a) Load duration curve and (b) daily peak load variation curve for the RBTS.

Appendix B

PJM Method

Table B.1: Annual wind power capacity credit for the month of July with Swift Current data

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	19.047	35	26.331	69	18.218
2	18.623	36	27.661	70	18.607
3	21.530	37	23.216	71	21.238
4	24.173	38	27.345	72	24.570
5	25.942	39	21.617	73	31.776
6	21.739	40	23.435	74	20.978
7	22.305	41	21.105	75	24.937
8	22.802	42	15.965	76	30.315
9	22.639	43	21.056	77	20.347
10	12.956	44	24.801	78	31.659
11	19.916	45	27.773	79	18.049
12	20.105	46	19.599	80	21.765
13	26.602	47	17.875	81	17.857
14	23.603	48	26.049	82	19.483
15	18.829	49	21.523	83	21.562
16	31.523	50	20.843	84	21.353
17	27.846	51	25.390	85	20.038
18	24.428	52	20.350	86	24.672
19	25.111	53	24.911	87	23.166
20	23.513	54	17.944	88	20.589
21	26.573	55	26.499	89	20.171
22	27.136	56	22.514	90	20.415
23	17.332	57	19.747	91	22.795
24	11.091	58	18.735	92	19.711
25	24.050	59	22.415	93	18.100
26	21.653	60	26.851	94	17.878
27	32.539	61	27.282	95	24.345
28	15.510	62	30.209	96	22.097
29	21.981	63	31.376	97	27.347
30	21.573	64	23.351	98	24.920
31	17.779	65	23.084	99	11.091
32	22.033	66	29.596	100	21.448
33	26.198	67	31.711		
34	19.010	68	20.960		

Table B.2: Annual wind power capacity credit for the month of July with Regina data

Year	CC (%)	Year	CC (%)	Year	CC (%)
1	31.609	35	41.534	69	28.204
2	28.856	36	42.339	70	28.399
3	35.101	37	31.870	71	30.858
4	34.518	38	41.938	72	35.951
5	37.128	39	32.014	73	43.723
6	34.395	40	32.709	74	30.137
7	35.523	41	32.177	75	39.362
8	34.402	42	26.125	76	42.940
9	33.291	43	34.197	77	31.569
10	22.371	44	38.419	78	49.025
11	27.900	45	38.710	79	29.219
12	30.836	46	30.418	80	33.577
13	37.350	47	28.112	81	30.242
14	35.124	48	40.041	82	30.901
15	26.800	49	32.915	83	34.310
16	46.075	50	31.313	84	34.598
17	41.005	51	38.515	85	30.358
18	37.874	52	34.355	86	37.839
19	36.475	53	35.513	87	32.261
20	32.078	54	28.287	88	29.755
21	37.276	55	35.995	89	31.166
22	44.220	56	34.478	90	32.653
23	23.677	57	31.728	91	32.901
24	17.785	58	31.526	92	30.007
25	35.872	59	31.586	93	27.042
26	32.772	60	38.011	94	29.887
27	44.065	61	40.057	95	34.506
28	26.696	62	43.073	96	31.319
29	33.713	63	40.656	97	41.446
30	32.550	64	31.796	98	35.688
31	26.543	65	37.722	99	21.294
32	34.076	66	43.063	100	31.903
33	34.289	67	44.788		
34	30.212	68	35.626		

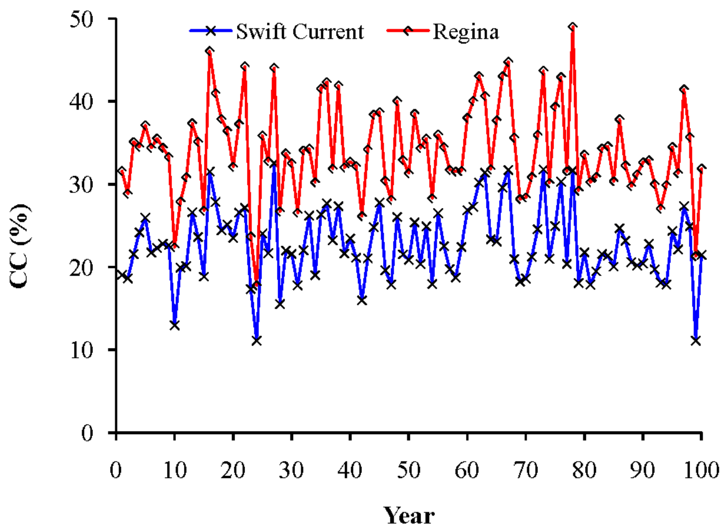

Figure B.1: Comparison graph showing the capacity credit values at Regina and Swift Current for the month of July.